D99-06-057

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Decision 99-06-057 June 10, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas and Electric Company (U 902-M) for Authority (i) to Increase its Authorized Return on Common Equity, (ii) to Adjust its Existing Ratemaking Capital Structure, (iii) to Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iv) to Decrease its Overall Rate of Return, and (v) to Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief.	Application 98-05-019 (Filed May 8, 1998)
Application of Pacific Gas and Electric Company for Authority (i) to Establish its Authorized Rates of Return on Common Equity for Electric Distribution and Gas Distribution, and (ii) Establish its Unbundled Rates of Return for Calendar Year 1999 for Electric Distribution and Gas Distribution. (Electric and Gas) (U-39-M)	Application 98-05-021 (Filed May 8, 1998)
Application of Southern California Edison Company for Consideration of Unbundled Rate of Return on Common Equity, Capital Structure, Cost Factors for Embedded Debt and Preferred Stock, and Overall Rate of Return for Utility Operations. (Electric) (U 338-E)	Application 98-05-024 (Filed May 8, 1998)

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OPINION

Summary

This proceeding addresses rate of return issues for the stand-alone electric distribution and gas operations of PG&E, SDG&E, and Edison. We hold that for the electric utilities the divestiture of generation and the FERC's regulation of transmission have not altered traditional methods of determining return on equity. We find that there is no need to have either a discount or a premium adjustment to the UDC return on equity. We find that Edison's 1996 PBR decision does not preclude its rate of return from being determined in this proceeding, however, we decline to modify Edison's return on equity at this time. We find the return on equity for PG&E and SDG&E to be 10.60%.

We find the rate of return for the electric utilities to be:

PG&E

	Cap Structure	Cost	Wgt Cost
Debt	46.20%	7.09%	3.28%
Pref	5.80%	6.55%	0.38%
Equity	48.00%	10.60%	5.09%
Total	100.00%		8.75%

SDG&E

	Cap Structure	Cost	Wgt Cost
Debt	45.25%	6.87%	3.11%
Pref	5.75%	7.76%	0.45%
Equity	49.00%	10.60%	5.19%
Total	100.00%		8.75%

Edison

	Cap Structure	Cost	Wgt Cost
Debt	47.00%	7.64%	3.59%
Pref	5.00%	6.62%	0.33%
Equity	48.00%	11.60%	5.57%
Total	100.00%		9.49%

For PG&E this represents a reduction in return on equity of 60 basis points; for SDG&E the reduction is 100 basis points.

For the gas distribution operations of PG&E and SDG&E we find that the return on equity is the same as the return on equity for the electric operations, i.e., 10.6%. We further find that the debt and preferred stock structures of the utilities are the same for gas and electric.

The estimated annual revenue requirement reductions for the utilities are:

	Electric	Gas
PG&E	($46,280,000)	($14,500,000)
SDG&E	($14,585,000)	($4,779,000)

Public hearing was held before ALJ Robert Barnett. There were 14 hearing days; the assigned Commissioner was present for 2 days. Oral argument before the Commission en banc was held April 19, 1999. Consistent with SB 960, this decision is issued less than 18 months from the dates the applications were filed.

Introduction

This proceeding is the first to address rate of return issues for the stand-alone electric and gas distribution operations of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison). With the unbundling of electric generation, transmission, and distribution operations, the only portion of the formerly vertically integrated electric utility remaining under the Commission's normal utility rate regulation is electric distribution operations.[1] In past cost of capital (COC) cases, the Commission authorized one rate of return for all the assets of the entire integrated utility. Unbundling requires us to take a new look at rate of return. For instance, in PG&E's 1997 COC decision, the Commission indicated that it would address the unbundling of cost of capital by directing the utilities to "propose unbundling of long-term debt, preferred stock, and the shareholders' equity to correspond to the business realities of 1998 when largely regulated distribution assets must be separated from largely deregulated generation assets." (D.97-12-089, mimeo., at 16.) PG&E and SDG&E have responded with a showing which addresses cost of capital issues for their electric distribution operations on a stand-alone basis. They also have presented testimony for stand-alone gas distribution. Edison's showing is somewhat different and we will address certain matters specific to Edison separate from other discussion.

[1] Electric transmission operations are now under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The transmission systems of the three utilities are operated by the Independent System Operator (ISO). Fossil generation of the three utilities is expected to be divested. Hydro plants may be divested as well, and generation pricing is subject to the Power Exchange (PX). Utility nuclear generation is subject to its own ratemaking and regulatory treatment.

I. Does Edison's Performance Based Ratemaking (PBR) Mechanism Preclude Consideration of Changes to its Rate of Return?

Edison argues that we should reject intervenors proposals to adjust its return on equity on essentially legal grounds, that our adoption of a cost of capital trigger mechanism in 1996 precludes us from considering changes to Edison's rate of return.

The Commission adopted Edison's PBR mechanism in D.96-09-092, which included a cost of capital trigger mechanism. Subsequently, in 1997, the Commission issued its decision on the functional allocation of costs which unbundled the rates of Edison, PG&E, and SDG&E . Among the issues addressed by the Commission in the ratesetting decision was whether the cost of capital should be unbundled (D.97-08-056). The Commission ordered the utilities to file applications in the 1999 cost of capital proceeding to consider unbundling cost of capital. Edison filed a petition seeking to defer consideration in light of the recently adopted cost of capital trigger mechanism. The Commission invited Edison to make its point in this proceeding.

TURN and ORA finds Edison's argument to be devoid of merit. They say that the Commission's PBR decision for Edison makes clear that Edison's return on equity would later need to be reexamined and perhaps changed to reflect separate returns for generation, transmission, and distribution. The decision states:

> "As a part of our unbundling proceeding in electric restructuring and with coordination in the cost of capital proceeding, we intend to order separate and distinct authorized equity returns for the generation, transmission and distribution operations." (D.96-09-092, p. 42.)

The Commission made its statement in D.96-09-092 to notify Edison that its return on equity would be reexamined in connection with unbundling. Later, in D.97-08-056 the Commission specifically ordered all three utilities, including Edison, to file for unbundled returns in the current cost of capital proceeding. The Commission directed this action almost a year after Edison's PBR. ORA asserts that if the Commission had intended to preclude reexamination of Edison's return on equity, the Commission would never have directed as it did in D.97-08-056.

ORA believes that Edison itself evidently took the view until recently that its return on equity should be reexamined in this proceeding. There is no reference in D.97-08-056 (directing the current proceeding) that Edison believed its PBR precluded an Edison cost of capital showing. In fact, D.97-08-056 states that Edison concurred with proposals for an unbundled cost of capital proceeding (D.97-08-056, pp. 18 and 19). Edison's argument that the Commission has already set an unbundled rate of return for its distribution system is nonsense, in ORA's opinion.

ORA points out that Edison's last formal cost of capital proceeding was A.96-05-032, and that the decision (D.96-11-060) set the authorized ROE of 11.6% for all Edison operations except nuclear generation. In other words, D.96-11-060 set a return for Edison's integrated operations, not its unbundled distribution operation. Furthermore, the 11.6% return was set before the unbundling proceeding even began.

We agree with TURN and ORA. Edison's statement in its brief (O.B. p. 3-4) that this Commission "explicitly stated the trigger mechanism would replace participation in the annual cost of capital proceeding" is without foundation. Edison cites Ordering Paragraph 17 of D.96-09-092, but that paragraph states in its entirety "Edison shall use its Trigger mechanism to update the authorized return on equity for the purpose of updating the net revenue sharing benchmark and for revenue requirement recovery." What D.96-09-092 does say is:

"As a part of our unbundling proceeding in electric restructuring and with coordination in the cost of capital proceeding, we intend to order separate and distinct authorized equity returns for the generation, transmission and distribution operations." (D.96-09-092, p. 42.)

Finally, in D.97-08-056 we ordered PG&E, SDG&E , and Edison to file for unbundled returns in this proceeding. There is no contradiction between our decisions. The Edison PBR decision was issued in September 1996. This decision is being issued in 1999. At the time D.96-09-092 was issued, we could not know when this cost of capital proceeding would be completed. It is clear that the Commission intended this proceeding to be used to assess whether changes to the cost of capital were required as a result of unbundling of utility operations. Edison's request that we reject the proposals to modify Edison's ROE outright is denied. Instead, we will first review whether the record supports any sort of risk premium adjustment as a result of unbundling before concluding whether to disturb Edison's cost of capital trigger mechanism.

II. Standard of Review

Although the Commission is only considering rate of return for distribution operations in this case, the standards are still those articulated in Bluefield Water Works and Improvement Co. v. Public Service Comm'n, 262 U.S. 679 (1923) and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In Bluefield Water Works, the Court stated:

> "A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by

> corresponding risks and uncertainties... The return... should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties." (Bluefield Water Works 262 U.S. at 692.)

In Hope, the Court reiterates the financial soundness and capital attraction principles of Bluefield:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends of the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." (Hope Natural Gas, 320 U.S. at 603.)

The rate of return on rate base authorized by the Commission must be sufficient to satisfy this standard in order to give utility shareholders a return commensurate with the risks of comparable investments. However, in applying that standard, we must not lose sight of our duty to protect the ratepayers from unreasonable rates.

The risk/return standard established by Hope and Bluefield is often met by identifying companies of comparable risk, and estimating the returns expected by shareholders of those companies. Currently, however, there aren't any domestic stand-alone electric utility distribution companies (UDCs). Without any pure UDCs to provide information on returns, the parties in this proceeding have either (1) used natural gas distribution companies as a proxy for electric distribution or (2) used traditional, integrated electric utility companies as a first approximation or (3) created novel theories of comparability. Some parties then adjusted their result (the "distribution risk" adjustment) to arrive at a UDC cost of capital.

The process of selecting a group of comparable companies, estimating the cost of equity capital for that group using different models and inputs, and then determining a distribution risk adjustment, if any, requires judgment at each step of the process, and that judgment invites controversy.

The arguments over financial theory and its application to the cost of capital modeling, the extensive differences of opinion over the merits and drawbacks of different models, and the varied attempts to find a way to assess the difference in risk and required return between the stand-alone UDC and the integrated electric utility present a multitude of alternatives needing resolution. There is, however, one common theme arising from the differences in theory, models, data, and their application which all parties share. That theme is the need and importance for the Commission to exercise judgment in evaluating the evidence and outcomes presented by the parties. Even under the best conditions, financial modeling is an imperfect tool dependent upon input assumptions that are unavoidably subject to varying degrees of error. We must exercise our judgment as to whether the outcome of a given analysis is consistent with or contrary to common sense.

III. Electric Distribution Utility Risk

The one new issue in this case is the question of whether and how unbundling and restructuring have changed or are changing the risk of the UDC, and the degree of change relative to the traditional integrated electric utility. The utilities see new and increasing risk for the UDC as a result of unbundling, restructuring, and the increase in competition which has begun to emerge as restructuring gets underway. The Office of Ratepayer Advocates (ORA) and the Utility Reform Network, Utility Consumers Action Network, and James Weil (together TURN) argue that the risk of the UDC is less than that for the integrated electric utility. The Federal Executive Agencies (FEA) and Czahar and Knecht (C and K) respond that they can't determine whether the risk is more, less, or the same, and support a review of the situation in a few years when more market data is available.

PG&E and SDG&E each recommend that in determining their 1999 ROE using traditional financial models we increase our result by 100 basis points and 20 to 100 basis points, respectively, to compensate for the increased risk caused by their becoming a distribution-only electric utility. Because they believe a distribution-only electric utility is less risky than an integrated one, TURN and ORA recommend a distribution risk discount of 30 to 124 basis points and 49 basis points, respectively. FEA and C and K recommend no adjustment for distribution risk. Edison takes no position, as it insists its ROE was determined in its last PBR decision (D. 96-09-092) and is not at issue in this proceeding.

Table 1 and Table 2 show the recommendations and the current ROE.

Table 1
ROE RECOMMENDATIONS

Recommendations A/			
Party	**Electric**	**Gas**	**Basis Points for Electric Distribution Risk (included in ROE)**
PG&E	12.10	12.10	+ 100
SDG&E	12.00	12.00	+ 20 to + 100
Edison	11.60	NA	0
FEA (all)	10.85	10.85	0
Knecht-Czahar (all)	10.80	10.80	0
Weil-TURN-PG&E	9.00	9.10	- 30 to - 124
-SDG&E	9.10	9.20	- 30 to - 124
-Edison	8.80	NA	- 30 to - 124
ORA (all)	8.64	9.32	- 49

A/ Before adjusting for the October 1998 DRI forecast.

Table 2

Current Authorized ROE		
Party	**Electric**	**Gas**
PG&E	11.20	11.20
SDG&E	11.60	11.60
Edison	11.60	-
CPUC Historical Benchmark[B]/	9.47	9.47

[B]/ October 1998 DRI forecast 30 year T-Bonds 4.71 + 4.76 (The average Commission authorized risk premium as computed by ORA).

A. PG&E

PG&E argues that there have been changes in both regulatory policy and market activity which point to growing distribution competition which was not present before. PG&E asserts that until 1998, this Commission did not show support for the introduction of competition into the electric distribution business. For instance, in late 1996 the Commission decided that if a proposed irrigation district built duplicative distribution facilities, PG&E's remaining ratepayers would be adversely impacted (Resolution E-3472, November 26, 1996). Other Commission decisions from the mid-1990's state that a primary purpose of Commission regulation has been to avoid unnecessary duplication. In Pacific Corp. v. Surprise Valley Electrification Corp., D.95-10-040, 62 CPUC2d 135, the Commission stated:

> "This Commission's specific constitutionally derived duty is the regulation of public utilities in California. As to electric utilities, whether they be investor-owned or cooperatives, our regulatory authority includes the structure and extent of service territories. This regulation is necessary to avoid unnecessary and wasteful duplication. From the inception of the Commission, a feature of its regulation has been the Commission's early determination that direct competition in

> the same geographic area where it would involve duplicating service facilities would be contrary to the public interest." (62 CPUC2d 135, 139).

As recently as 1997, the Commission reiterated the concept disfavoring distribution competition in the Application of Mather Field Utilities, Inc., D.97-04-084, mimeo., pp. 19-20, where it stated "[e]xclusivity, or freedom from competition, traditionally has been part of certificates granted by the Commission," in granting Mather Field Utilities an exclusive gas distribution franchise.

However, in 1998, PG&E sees an apparent change in regulatory policy regarding distribution competition involving distribution facilities. In June 1998, the Commission issued D.98-06-020 on the proposed PG&E/Modesto Irrigation District (MID) sale. The Commission in that decision indicated that it finds distribution facilities competition acceptable, stating:

> "...in general the Commission's policy is to promote competition in all markets where competition may be economic. Apparently, competition in transmission and distribution markets may be possible in some areas of the state...Where economic competition is possible, and where other public policy goals are not unduly compromised, our policies will promote competition in utility markets." (D.98-06-020, mimeo., pp. 7-8).

Besides this change in policy in the MID decision, PG&E refers to Resolution E-3528 where the Commission found that potential construction of duplicative distribution facilities provides a competitive check on the ability of the utility to pass through costs (Resolution E-3528, discussion Paragraph 7, April 23, 1998).

PG&E's witness testified about signs PG&E is seeing in the marketplace that herald the beginning of distribution competition, including market activity by irrigation districts and important developments in distributed generation. He said MID has used its competition transition charge (CTC) exemptions to take large customers in Oakdale, Escalon, and Ripon away from PG&E. In a matter of months, MID has installed duplicative facilities and started to serve customers. MID has been selected by the San Joaquin County Board of Supervisors to provide electric service to a new development near Tracy. Meanwhile, Merced Irrigation District has begun construction of a 33-mile 115 kV transmission loop. And other irrigation districts, both existing and proposed, have expressed their interest in acquiring significant customer loads for electric distribution service.

PG&E does not expect the competition for distribution facilities service to extend to all customers or cause wholesale duplication of entire distribution systems. Instead, it believes competitors are concentrating on major customers who provide high margins. What is developing is a patchwork of small distribution systems which are situated to cherrypick the most profitable customers. This aspect of distribution competition would have at least two effects. First, the distribution utility may lose customers who provide significant contributions to margin. Second, the competition for customers may provide broad price signals having the potential to affect margins systemwide, most likely downward.

In addition, PG&E believes distributed generation (DG) is poised to compete with electric distribution service for the customer's business.[2] PG&E's witness testified that DG is an emerging technology which is expected to increase over the next several years as the deregulation of the U.S. electric industry drives

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[2] Distributed generation is smaller size generation technology that may be located on the customer's site or at strategic locations on the distribution system.

demand for distributed generation. Recent technological developments have now made it possible to install DG in modular units.

PG&E contends that the changes in regulatory policy and market activity which it has seen this year are altering the landscape in favor of distribution competition; it points to increased risk for the UDC as it moves into an unbundled, restructured environment. PG&E believes that the direction of change in risk for the stand-alone UDC is upward. PG&E's study of restructuring impacts in other industries indicates that the return required for the regulated distribution system post-restructuring increases substantially above the level required for the formerly integrated utility. PG&E seeks an upward adjustment of 100 basis points in the return on equity to recognize the direction of the change in UDC risk.

B. SDG&E

SDG&E asserts that it is not a pure distribution utility; its unbundled UDC business is not purely a "wires" business, although it has a substantial wires service component. It argues that for purposes of describing risk that drives an appropriate return for investors, the business realities facing SDG&E involve not only wires service but more broadly a combination of public utility activities that remain subject to this Commission's jurisdiction. In addition to distributing electricity, SDG&E provides bundled commodity services to all customers that desire such service, whether by choice or on a default basis. SDG&E owns a 20% share in the San Onofre Nuclear Generating Station. SDG&E retains its contractual obligations to purchase power from other utilities and qualifying facilities (QFs). SDG&E also provides revenue cycle services. It notes that approximately 93% of its total revenue on a 1999 forecast basis remains subject to this Commission's jurisdiction. The balance, comprising forecast revenues from SDG&E's fossil generator and transmission business components, is subject to FERC's jurisdiction. SDG&E anticipates that during 1999 it will divest itself of ownership in all of its fossil plants, but until such time SDG&E owns and operates these fossil plants. Further, after divestiture it will continue to operate these plants for at least a two-year period. It is the risk of variability or volatility of earnings that is associated with this combination of business activities - all performed under a rate freeze - that an investor examines and what this Commission is legally obligated to consider when authorizing a return on equity.

SDG&E's witness testified that under the rate freeze, commodity risks associated with ISO and PX market operations are substantial. The UDC remains obligated to provide commodity service to all customers that continue to be served by the UDC either by choice or through default of an energy service provider. The commodity is acquired through the PX during the transition period (the period of the rate freeze). Purchases of commodity always involve risks to the utility providing service.

Focusing on the transition period, high PX and ISO market prices will cause a risk of cost underrecovery, including commodity costs, because of the rate freeze. SDG&E believes the risk is more serious than originally contemplated. Its witness testified that during the first several months of operations, the ISO and PX operations have created substantial price volatility in the energy and the ancillary services markets. Both the PX hourly day-ahead prices and the ISO ancillary service prices continue to experience severe upward price fluctuations. The hour ahead and ex-post prices have reached $250/MWhr during approximately 40 hours. The ISO's ancillary service prices have also been extremely volatile with prices as high as $9999/MW during July. Subsequently, the ISO initially capped the rates it was willing to pay at $500/MW, which it later reduced to $250/MW, to mitigate what the ISO characterized as market dysfunction. The ISO is considering eliminating these caps.

SDG&E contends that the ISO dispatches SDG&E's generation in an extremely inefficient manner in contrast to SDG&E's historic operation of its generation. This inefficiency has raised the cost of energy and ancillary services. ISO operations include running inefficient gas turbines much more than was appropriate; running several more units than were required to maintain system reliability; dispatching must-run generation before exhausting available market bids; going out of market to buy generation at excessive prices of more than $200/MWhr; going out of market to sell excess generation at negative prices, i.e. paying out of state utilities to take power; and restricting access to ancillary services markets which has had the effect of making these markets even thinner and less competitive with resulting higher, more volatile prices.

SDG&E's witness testified that the risk associated with the substantial commodity price volatility that the market has experienced to date creates a material risk to the UDC's ability to recover revenue requirements associated not only with the transmission and distribution components of rates but also CTC. This exposure is substantial, in SDG&E's opinion. For example, if SDG&E's Schedule PX rate was 5 cents/kwhr and SDG&E was charging an average of 3 cents/kwhr for commodity, then SDG&E would be paying the PX more for the energy and ancillary services delivered to customers than what it was charging its customers. When this occurs, as it did during August, September, and October, 1998, it could impact SDG&E's ability to fully collect CTCs during the transition period. SDG&E claims that its undercollection exposure of at least 2 cents/kwhr during a three-month period, such as occurred during August through October, is about $80,000,000.

SDG&E is concerned that in the event a direct access customer's energy service provider fails to have a scheduling coordinator, then the UDC as the default provider is exposed to increased costs due to unaccounted-for energy. The period of time this risk may last can extend for weeks if adequate notice is not provided to the UDC. Currently, approximately 14% of SDG&E's customers have selected direct access service. Therefore, while the risk associated with unaccounted-for energy is presently small, it is growing and, incrementally, it is one more cost that places greater risk on earnings volatility.

SDG&E says that it is currently experiencing competitive pressures in its distribution business by the active marketing efforts of some 59 new marketers in its service area. Of these, 13 electric service providers (ESPs) representing approximately 14% of SDG&E's electric load provide a variety of services, including commodity, billing, meter installation, and meter data management services. Such market penetration over an eight-month period strongly suggests to SDG&E that it will see many more competitors in its service area. Subsequent to April 1, 1998, SDG&E has received five inquiries from customers seeking to bypass its UDC system by means of constructing their own substations which permit direct access to the transmission grid. One large industrial customer has already contracted with an ESP to provide for the installation of such a substation. This customer tentatively could reduce its bill from SDG&E by $250,000 to $300,000 per year, which represents distribution bypass. Prior to the commencement of restructuring, SDG&E experienced three similar inquiries over a period of 20 years. If SDG&E were to attempt to maintain these customers by means of a rate discount, SDG&E would bear the cost of such discount, which would reduce realized return on equity.

SDG&E contends that there is a large degree of uncertainty as to the likelihood of full stranded cost recovery as a result of activities beyond its direct control.[3] It says this uncertainty, as well as uncertainty over the recoverability of the cost of commodity or revenue requirements for distribution and transmission, is even greater for SDG&E than for Edison and PG&E since these companies can more rapidly recover their stranded costs due to the QF "cliff". This "cliff" represents a reduction of QF payment exposure by Edison and PG&E and, thus, substantially improves the probability that these two utilities may be able fully to recover their CTC. SDG&E will not see such a steep drop off in QF payments because it does not have anywhere near as large a commitment to QFs. SDG&E attributes approximately 50 basis points of the 100 basis point premium resulting from unbundling to increased risk resulting from SDG&E's having such a small drop off in QF payments during the transition period.

SDG&E believes the risks it has described and is experiencing in the distribution business require a 20 to 100 basis point premium.

C. Edison

Edison, although claiming that its rate of return is not subject to this proceeding, out of an abundance of caution has presented testimony on distribution risk.

Edison argues that the risks of an unbundled UDC are equal to or greater than integrated utility operations; the UDC bears much greater risk during the transition period and thereafter. Edison believes that the UDC bears a significant energy procurement risk. During the transition period, utility rates are frozen at the June 10, 1996 level. Within the frozen rate level, the utility must recover its operating costs, the costs of procuring sufficient energy and capacity

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[3] SDG&E has recently filed A.99-02-029 to terminate the rate freeze as of July 1, 1999, because it will have recovered its full stranded costs by that time.

to meet its load, pay for mandated public purpose programs, and recover its transition costs. If its operating or energy procurement costs rise, the UDC's shareholders may not be able to fully recover transition costs. The energy procurement cost is the most highly variable component of the utility's frozen rate and is completely outside the control of the utility. Customers are shielded from the risk of price increases during the transition period; utility shareholders bear the entire risk. This risk is not a generation-related risk and therefore cannot be ignored in setting the UDC's return. Utility shareholders bear the risk of recovering transition costs through the UDC's rates during the transition period. While the transition costs may have been largely related to generation assets, it is the UDC that is at risk if these costs are not recovered during the transition period.

Edison contends that there are also greater risks for the UDC during the restructuring process. The legislative underpinnings of the restructured industry have been subject to challenge in the initiative process. There may be other efforts to deny UDCs the opportunity to fully recover their transition costs. The ISO and PX are new market structures that are evolving in ways that create uncertainty for investors. There are uncertainties regarding the recovery of capital additions Edison made in 1997 and 1998 prior to the commencement of the generation market. These aspects of the restructuring process are viewed by investors as significant potential risks that must be compensated for in the allowed return on equity, in Edison's opinion.

Edison claims the new industry structure has risks the UDC has not previously borne. It notes that the Commission is opening revenue cycle services to competition from energy service providers. How revenue cycle service costs are allocated and the utility's ability to recover its costs are much more uncertain now than under integrated utility operations. The UDC bears some risk of default by energy service providers, despite the efforts of the Commission to mitigate these risks. Because Edison's total rate level is frozen , there is the potential for the Commission or other governmental agencies to mandate new utility activities with no opportunity to collect offsetting revenue to recover the associated costs. Finally, there is a growing risk of competition from distributed generation, cross-fuel competition from natural gas, and bypass of the utility as competitors seek ways to exploit the newly created market.

D. TURN

TURN argues that unbundled distribution risks are lower than integrated utility risks. It cites five areas: (1) Wall Street assessments of distribution risks, (2) the likelihood of stranded distribution costs under competition, (3) engineering and economic fundamentals regarding distribution and generation facilities, (4) the history of regulatory risks, and (5) measured variability of distribution and generation costs.

TURN believes that financial community reaction to the unbundling of distribution service provides an important reality check on business risks. It says Wall Street plainly disagrees with the testimony of the applicants. In October 1995, Fitch Investors Service issued a special report on unbundling electric utilities. The report concludes that the generation sector is likely to be the most volatile. The Fitch report states:

> "Under the current cost-of-service regulation, utilities have experienced greater regulatory risk associated with generation than in their distribution and transmission activities.

In October 1996, Duff & Phelps, a credit rating agency, issued a special report on credit quality implications of electric industry disaggregation. The report states:

> "In general, it is reasonable to expect that within a given rating category companies involved in only the distribution and transmission segments of the electric utility business will have a lower business risk profile."

In May 1997, Standard & Poor's CreditWeek published a feature article that concluded that electric transmission and distribution companies have relatively low business risk. The article states:

> "Tightly regulated transmission and distribution utilities generally face limited business risk and can operate with relatively low operating margins and high leverage. Conversely, generating companies operating in a very competitive environment face much higher business risk and attendant cash flow volatility, and therefore generally can sustain only modest levels of debt."

In October 1997, Moody's Investors Service, a debt rating agency, issued a Special Comment report on electric distribution providers. Moody's concluded that distribution firms are more stable than generation service providers and that cash flow coverage ratios will remain the most important measure of financial risk.

TURN says it is unlikely that significant stranded distribution costs will appear. PG&E's estimate of new distribution bypass in the test year is less than 0.4% of sales. SDG&E and Edison have not even tried to forecast distribution bypass. The primary generation risk during the transition from cost of service regulation to competition is the disposition of stranded or uneconomic assets. The Commission authorized a low ROE to reflect reduced risks.

TURN contends that distribution facilities will not be stranded in the same way that expensive utility generation facilities were stranded because generation could not compete in the open market. Commodity electricity can be readily transported over the transmission grid, and all generators can compete against each other. On the other hand, distribution service is not a commodity that can be transported from one place to another, and distribution facilities will see few if any competitors. Distribution competition will be limited to service territory threats from a few alternate providers. Loss of service territory alone does not cause stranded costs.

TURN explains that on the distribution side, CTC exemptions and irrigation district tax advantages are the primary drivers of competition. These factors lead districts to take over utility facilities and service territory, but they do not encourage construction of duplicative facilities. In fact, building duplicative facilities is counter-productive because it introduces competition that would not exist if the district buys or leases utility facilities. Unlike generation, duplicative distribution service cannot be shipped elsewhere in search of sales. Utility resistance to takeovers may cause some duplication of distribution facilities, but duplication will be limited overall. When and if irrigation districts buy utility distribution facilities, sales prices will likely exceed book value, without stranded cost risk to investors.

TURN maintains that the risks of mechanical failures and consequent financial harm are lower for distribution service. Distribution technology is less complex than generation technology, and complexity is directly related to the risk of failure and increased earnings variability. Distribution systems are collections of standard, off-the-shelf components like poles, wires, transformers, and circuit breakers. Generation systems also include standard components, but individual power plants have unique designs, and major components are manufactured one at a time with long lead times.

Mechanical and electrical failure within distribution systems carry lower potential to affect utility earnings, in TURN's opinion. A single distribution component failure may affect utility service in a neighborhood or local area, but repairs can usually be made quickly. A single generation component failure can take billions of dollars of assets out of service and cause substantial repair and replacement power costs. Overall, distribution failures have a reduced impact on earnings, compared to generation failures.

TURN suggests that distribution systems are less vulnerable to cost disallowances ordered in Commission reasonableness reviews. The most significant disallowances and related settlements in recent years have arisen from reviews of large capital projects and gas transmission practices. Examples include PG&E's Diablo Canyon Nuclear Power Plant, the San Onofre Nuclear Generating Station owned in part by Edison and SDG&E, and PG&E's Canadian gas transactions. There has been no distribution disallowance of comparable importance.

Finally, TURN says that the variability of costs for distribution service is markedly lower than for generation. Investors are rewarded for the earnings risks they undertake, and risk is defined as the uncertainty or variability of outcomes. (D.94-11-076, Finding of Fact 21, 57 CPUC2d 533, 561.) There is no convenient method for unbundling past utility earnings into generation, transmission, and distribution components, but accounting records contain information about the variability of expenses. In order to test the variability of cost streams alone, TURN reviewed PG&E's electric generation, transmission, and distribution expenses, and approximate returns on rate base. TURN computed cost variability for 10 years of recorded data. The results show that the variability of generation costs is roughly four times the variability of distribution costs, and the variability of transmission costs is roughly 1.3 times the variability of distribution costs. TURN's study is limited to utility costs, but the results strongly suggest that distribution and generation earnings variability have followed cost variability. Bundled service in past years implies that variations in revenues assigned to individual services will track one another.

As a result of its analysis, TURN recommends a 30 basis point reduction in ROE.

E. ORA

ORA argues that applicants should be considered distribution only utilities and found less risky than integrated utilities. ORA supports TURN's reasoning. ORA makes the distinction between diversifiable risks and nondiversifiable risks, with only nondiversifiable risks requiring compensation in return on equity. It provides an example of a nondiversifiable risk: the state of the economy. If the general economy is bad, an investor cannot diversify that risk by diversifying his investment. Virtually all companies are affected by a weak economy. ORA asserts that every risk which the utilities have identified is diversifiable. That is, a prospective investor facing such utility risk can diversify away the risk by purchasing other securities. The risks identified by the utilities are either unique to one utility, unique to California utilities, or are symptomatic of utilities generally. Each such risk can be diversified by purchasing stock of utilities outside California, or by purchasing non-utility stock. As such, this Commission cannot compensate the utilities for these risks, regardless of their degree.

ORA maintains that the risks identified by the utilities are relatively minor ones, whether they are diversifiable or not. The three utilities are in better shape than ever. Generation, the most risky element of their business, has been dealt with by divestiture. Their remaining business is the distribution of electricity and gas. The distribution system remains regulated. Rating agencies find California distribution utilities to be in a strong position. The California utilities are also in a strong position to collect all of their transition costs. The utilities themselves believe this, and they provide such information to their investors.

But, regardless of definition, ORA states that the Commission does not need to judge whether a risk is minor or diversifiable. The risks, and investors' views on the risks, are captured by financial models. Thus investors' views of whether a company or industry is risky, the degree of the risk, and its diversifiability, are contained in the model results. That presents yet another reason to trust the model results, rather than torturing the results to increase return by identification of risks which are conjectural.

ORA believes the commodity price risk is a risk of generation, not distribution. It is a transition cost recovery risk. Given this general foundation, ORA recommends that the Commission find that consideration of changes in ROE which are related to transition cost recovery would violate Assembly Bill (AB) 1890, effectively modify the Commission's own policy decision of this issue, result in double recovery for transition cost risk, and undermine the basis for the competitive generation market and restructuring itself. ORA states that it is difficult to envision a set of findings that could wreak greater damage.

ORA contends that while AB 1890 is complex, the central structure is this: utilities have an opportunity to recover 100% of their uneconomic costs at a reduced rate of return by the end of 2001 within frozen rates. If utilities successfully manage their costs, they will recover their investment in generation-related assets plus a reduced rate of return on those assets. Thus, under AB 1890 all risks associated with the rate freeze were incorporated in the reduced rate of return. To grant an increase in the UDC's ROE for risks related to the rate freeze has precisely the same effect as increasing the reduced rate of return on utility generating assets.

ORA argues that allowing a particular form of transition cost risk to be reflected in ROE constitutes no less than double payment by ratepayers. Utility testimony clearly associates commodity price risk with the risk of asset recovery under the rate freeze. Clearly, both the Commission and Legislature have considered and explicitly determined the appropriate level of return for transition cost recovery. Reflecting commodity price risk in the distribution rate is profoundly anticompetitive. Commodity price risk affects the pricing of, and competition for, competitive generation services. Just as the commodity price risk varies for purchases from the PX, it will vary for other producers and providers of energy. Those providers must recover their commodity price plus a profit from the marketplace. The utility would not have to recover its profits from the marketplace. Those profits would be in the regulated cost of service distribution rate. If all else were equal, non-utility providers could not stay in business. The utility would buy and sell at the PX price, and earn a regulated profit. A non-utility provider would have to buy and sell at the PX price as well, or lose the customer's business. The result: no profit opportunity, no competition, and no direct access market. That outcome could not be more at odds with the Commission's overall restructuring policy.

ORA concludes its analysis of risk with the comment that volumes could be written about competitive risks, but there is no need to do so here. Utilities have faced and continued to face bypass risk in pockets of their system. Irrigation districts have long had the ability to expand into the utility's franchise territory. PG&E has provided evidence of duplication and bypass in three instances, totaling less than one million dollars. While there are clearly shallow pockets of competition, competition hardly threatens the utility's remaining services. Granting the utilities even one basis point for distribution competition would outweigh the lessened competition the utilities now face.

ORA recommends a 49 basis point reduction in ROE to compensate for reduced risk.

F. Czahar and Knecht (C and K)

C and K put little credence in the utilities' request for a risk premium because of procurement risks, or for that matter, any risks peculiar to a distribution-only utility. In regard to the utilities' claim that their UDC operations require a procurement risk premium for the possibility that high fuel costs in the next few years may keep them from fully recovering their stranded costs, C and K argue that the claim misses the symmetry of the situation, which mitigates the risk greatly: fuel prices may be low in the next few years, in which case they would tend to assure full recovery of the stranded costs, not diminish that likelihood. Further, they note that all three utilities have indicated on the public record that they expect full recovery. Thus, there is small procurement risk.

On the opposite tack, C and K reject ORA's and TURN's call for a distribution risk discount. C and K performed a multi-variate statistical analysis using a wide sample of electric utilities. Their regression analysis tested whether the result of each method for estimating the ROE (four discounted cash flow (DCF), three capital asset pricing model (CAPM), and two risk premium (RP) methods) varies with the percentages of generation, transmission, or distribution (%G, %T, or %D) in the business mix of a utility. Their results show that %G, %T, or %D never appear as significant determinants for each of the nine methods. That is, the ROE, as estimated by each of these models, is invariant with the relative fractions of generation, transmission, and distribution in an electric utility's business mix under utility regulation in the United States. This result means that estimates based on the universe of domestic electric utilities for which data are available are good proxies for the UDC. They conclude:

> "No sound basis has yet been shown for different ROEs between electric-utility G, T and D sectors, as such. If efficient capital markets

> required differentials due to different levels of business risk inhering in G, T and D, our multiple-regression analyses almost certainly would have revealed that. Thus, we reject such differentials at this time as unfounded and unsound. The G, T and D factors did not play a significant role in any regression equation." (Exh. 23, p. 26, II. 3-7.)

G. FEA

FEA takes the position that it is too early to determine whether a distribution-only UDC has functions more risky or less risky than an integrated electric utility, with a concomitant upward or downward adjustment to the return on equity.

In calculating the appropriate cost of common equity, FEA applied the same financial models as it did in previous years, and used the same versions of those models. However, those financial models have been applied to different groups of proxy companies necessitated by the change in focus to estimating the cost of equity for the distribution function. FEA has not used the occasion of the change in focus to change its basic approach to estimating the cost of equity. FEA does recognize that many of the issues raised are new to this proceeding with uncertain outcomes.

FEA says that the changes brought about by unbundling are so new and uncertain in result that it cannot be known at this time whether they will increase or decrease risk. Plausible arguments can be made on both sides of the argument. What does seem clear to FEA is that ultimately it will be the reaction of the financial markets to these issues, and its perception of the risk associated with the Commission decisions, that will determine the effects on the cost of equity. It is too early to tell how the financial markets will react. It is also unfortunate that the positions adopted on the issues, although predictable, have resulted in a broad range of cost of equity recommendations.

FEA makes no adjustment to its ROE for exogenous changes in risk.

H. Discussion

California formally began its quest to introduce competition into the electric services industry in April 1994, when this Commission instituted an investigation and rulemaking into that industry. (I.94-04-032, R.94-04-031.)[4] After more than a year and half of receiving evidence and comments from almost 500 persons and entities, we issued D.95-12-063, as modified by D.96-01-009, which enunciated our views of a restructured electric services industry which is expected to provide competition and downward pressure on the cost of electricity. We said "Our proposal today unbundles traditional utility services into generation, transmission, and distribution functions. . . . In the restructured industry, [utilities] would continue their obligation to provide distribution services to all customers, including direct access customers, in their service territories." (D.95-12-063, D.96-01-009 at pp. 84-85.)

We pursued our restructuring effort on many fronts, at the federal level, in the State Legislature, and in numerous decisions. But, for the purposes of this cost of capital decision, our pertinent decisions are few. In D.96-09-092, Edison's PBR decision, we said "As a part of our unbundling proceeding in electric restructuring and with coordination in the cost of capital proceeding, we intend to order separate and distinct authorized equity returns for the generation, transmission and distribution operations." (Id. p. 42.)

[4] These decisions were preceded by our Division of Strategic Planning's Yellow Book which discussed the need for competition. The Yellow Book itself resulted from our 1992 request to examine trends in the electric industry (D.92-09-088, p. 17).

In D.97-08-056 (the unbundling proceeding to accomplish the policy set forth in D.95-12-063 and D.96-01-009) we said "We will consider unbundling utility cost of capital in the generic cost of capital review proceedings as proposed by PG&E and SDG&E in their comments on the proposed decision and will direct the utilities to file applications on May 8, 1998." (Id. p. 19.)

We ordered Edison, SDG&E , and PG&E to file their applications seeking review of their cost of capital for the 1999 test year. (D.97-08-056, p. 62, Ordering Paragraphs 6, 7, and 8.) Finally, in D.97-12-089 (PG&E's last cost of capital decision) we said in reference to PG&E, SDG&E , and Edison,

> "For 1998, the utilities' filings for ROR and ROE will not utilize the incremental basis we apply in this decision, but will propose unbundling of long-term debt, preferred stock, and shareholders' equity to correspond to the business realities of 1998 when largely regulated distribution assets must be separated from largely deregulated generation assets. Thus, next year's cost of capital proceeding will be substantially different from those of recent years." (Id. p. 16.)

We have reviewed our decisions on electric restructuring and unbundling for two reasons: 1) to show that restructuring and unbundling are procedures well known in California and the United States since at least 1992; and 2) to show that seeking the appropriate cost of capital for an unbundled distribution system was not intended to be a mere intellectual exercise, but was to "correspond to the business realities of 1998."

PG&E and SDG&E and all intervenors other than TURN have approached the determination of the appropriate return on equity in the same manner. They determine the ROE using traditional financial modeling; then the parties that find it, adjust their result by a "distribution adjustment."

- PG&E and SDG&E add basis points because in their opinion a distribution electric company is more risky than an integrated electric company;

- ORA subtracts basis points because in its opinion a distribution electric company is less risky than an integrated electric company;
- TURN, using an incremental approach based on its filings in earlier cases, subtracts basis points for the same reasons as ORA;
- FEA and C and K make no adjustment because their analysis shows no difference;
- Edison makes no recommendation because it believes it is only a spectator in this proceeding.

The distribution adjustment is the overriding issue in this proceeding. With the adjustment the spread in ROE reaches from a low of 8.64% (ORA) to a high of 12.1% (PG&E). Without the adjustment the spread is a more manageable 9. 13% to 11.6%.

An integrated electric utility is often described as consisting of three distinct components - generation, transmission, and distribution. Prior to electric restructuring rate of return was determined on the basis of the integrated unit, not the sum of its parts. After electric restructuring the generation function and the transmission function have been considered separate functions to be treated, in an economic sense, apart from each of the other functions. Generation has been deregulated (AB 1890); transmission is now regulated by the FERC; leaving, residually, the distribution function to be regulated by this Commission.

Conventional wisdom has it that in the integrated unit the generation function is considered the most risky function, transmission and distribution less risky. Therefore, when considered separately, whatever the rate of return was for the integrated unit, the less risky distribution-only rate of return should be lower. This is the contention of ORA and TURN. The utilities see it differently. They contend that the distribution-only function, bereft of the support of its generation and transmission balance is naked to the buffeting winds of competition and, therefore, requires a higher rate of return. In this proceeding there is little controversy over debt and preferred stock; the entire thrust of each party is on return on equity.

All parties agree that the riskier a company appears to be, the higher the return on equity will be demanded by investors. It is on that basis the PG&E expert would add 300 basis points to the 7.5% after-tax weighted average cost of capital of an integrated electric utility to compensate for its loss of generation and transmission. (Exh. 1, pp. 1-5.) However, the expert tempered his estimate by actually recommending a 100 basis point upward adjustment to his benchmark 7.5% to arrive at an 8.5% after-tax weighted average cost of capital, which yields an ROE for PG&E of 13.1%. PG&E's policy witness, recognizing the uncertainties of the times and to balance shareholder and customer interests, requests an ROE of only 12.1%. (Exh. 1, pp. 1-5.)

SDG&E 's expert, using more conventional methods, recommends that SDG&E 's unbundled distribution business be allowed an ROE in the range 11.6% to 12.8% (Exh. 6, p. JVW-34). SDG&E 's policy witness recommends an ROE of 12.0% (Exh. 6, p. CAM-12), although he believes a 100 basis point upward adjustment for the new regulatory scheme would be reasonable (Exh. 6, p. CAM-10).

Edison, for reasons discussed elsewhere in this opinion, requests a continuation of its 11.6% ROE. It did, however, present an expert to discuss the risks of the new regulatory scheme. His analysis found a risk-return differential of 30 basis points between a distribution business and a vertically integrated operation, with distribution the less risky component (Exh. 10, p. 47). Nevertheless, he says that his estimates of the risk of the wires business are conservative "because they ignore the lost benefits of vertical integration. The mere act of unbundling the business will make each of the newly formed independent businesses riskier in the future." (Exh. 10, p. 39.)

The experts of all three utilities cite the same competitive threats and risks inherent in the distribution business which, in their opinions, require an increase in ROE.

- Competition releases competitive energies; one cannot predict how non-utilities will react to the deregulated industry,
- Metering and billing functions are currently under attack and high margin customers are the target,
- UDC's costs are fixed; they cannot be reduced if demand is reduced,
- There are no balancing accounts to match costs and revenues; there is a commodity price risk,
- Bypass is a distinct possibility; municipal districts are entering the electric distribution business,
- Distributed generation may be the first step to bypass,
- Regulatory risk - rapid changes by legislatures and commissions create uncertainty,
- Procurement risk - the UDC may not be able to recover the full cost of energy purchased on behalf of its customers,
- The risks and rewards of performance based regulation, and
- For SDG&E , its QF cliff.

ORA and TURN do not accept the utilities' arguments, claiming they are more theoretical than real. They believe the evidence shows that in the actual world of investors and current regulation the distribution business is less risky than the integrated utility and, therefore, should have a substantially reduced ROE.

We will not discuss each potential risk to determine its viability. For the reasons set forth below we find that a distribution only UDC is neither more nor less risky than a vertically integrated electric utility. Our starting point is Bluefield and Hope. The return should be commensurate with the expected return on investments with similar risks.

ORA asserts that "the Commission is not and should not set a rate of return for the firm or for the utility as a whole, but for the property that is the subject of this proceeding," which are "the risks of activities included in those unbundled distribution rates." (ORA Reply Brief p. 17.)

Here we are setting a return so that shareholders have the opportunity for earnings commensurate with investments of similar risks. We cannot, by fiat, say that some risks do not exist, e.g., procurement, commodity price volatility. The focus of this proceeding is the appropriate return for UDC operations. Although, the three utilities are not pure distribution utilities now and will not be pure distribution utilities for the foreseeable future, a separate return has been established for generation assets. However, at this time, the UDC is more than a "wires and meters" business. For example, the utilities retain significant responsibilities serving as the electricity providers of last resort.To properly reflect the Bluefield and Hope criteria we cannot base our result on less than the actual operations of the utility (recognizing that the FERC has set the transmission return and that the return for generation assets has also been previously set). This does not contradict our decision to consider the cost of capital for unbundled operations (D.97-08-056 at p.19). We have considered that cost and find that it is comparable to bundled operations.

The evidence that PG&E and SDG&E require a premium on ROE because of increased risks is not persuasive at this time. We accept that the distribution function is less risky than competitive generation functions. TURN's and ORA's discussion of rating agencies' opinion is pertinent. We note that financial rating agencies advise clients that distribution companies have less risk than generation companies. Moody's is directly on point: "The wires business will entail the lowest business risk of the future distribution business lines. . . .Although performance-based ratemaking and the effects of regulatory lags to recoup weather-related expenditures for example, may add some slight volatility to its cash flows, the wires business's prospects will remain highly predictable." (Exh. 12, Att. 7, p. 3.) S&P states "Standard & Poor's measures financial strength by a utility's ability to generate consistent cash flow to service debt, finance operations, and fund investment. . . .Tightly regulated transmission and distribution utilities generally face limited business risk and can operate with relatively lower operating margins and high leverage." (Exh. 12, Att. 8, p. 28.)

The utilities' argument that Moody's and S&P's recommendations are only valid for bond purchasers is unpersuasive. If anything, investors in equities are more concerned about risk than bond investors. We cannot envision how a company's risk could be lessened for prospective bond purchasers at the same time it is rising for prospective equity purchasers. Based on this review we find no premium is warranted.

In regard to the litany of risks proffered by the utilities we are of the opinion that although real, they are exaggerated. TURN has described that exaggeration. Distribution competition is limited relative to generation competition because generation can be transported wherever there are wires, but distribution competition is localized. Irrigation districts have little incentive to build duplicative systems because that would put them in competition with massive utility companies. Distributed generation and other forms of bypass have potential, but are in their formative stage and their impact will be further assessed in the Distribution Rulemaking, R.98-12-015. Whether they will be a serious threat is too early to tell. There is less variability in distribution costs relative to generation. And at present any loss of revenue because of price and procurement risks appears minuscule when compared to total revenue.

More persuasive to our conclusion that no premium is due are the views of FEA and C and K, as well as the testimony of ORA's expert and the market fundamentals espoused by PG&E's, SDG&E's, and Edison's experts.

FEA's expert refused to base his opinion on his subjective perception of whether a distribution-only electric utility was more or less risky than an integrated electric utility considering the risk-affecting factors assumed by the other witnesses. He based much of his analysis using a group of natural gas local distribution companies as a proxy for the unbundled electric distribution company. Both SDG&E's expert (at Ex 7, p. JVW-7) and Edison's expert (at Ex 10, p. 24) agree that LDC's are a valid proxy. FEA's expert believes the proper approach is to use traditional financial methods applied to companies closely comparable to a distribution-only utility. The results of that exercise would serve as the foundation for the ultimate judgment of the ROE. In his opinion, it is inappropriate to add or subtract basis points for perceived changes that cannot be gleaned from financial models. (Although he, as do all the witnesses, states that financial models are the basis for judgment, not a substitute.)

We have set forth C and K's opinion above. They conclude that their statistical analysis does not show variations for companies having more or less distribution risk in relation to generation and transmission. They would neither add nor subtract basis points based on perceived subjective changes for a distribution-only electric utility. They point out that years have passed to permit the financial markets to have absorbed the effects of restructuring changes and expectations, yet their analyses of financial data could disclose no difference in risk between electric companies with different distribution, transmission, and generation ratios.

PG&E's expert testified "the cost of capital is determined in capital markets, market values both determine and reflect its risks, and market values must be used to calculate it." (Ex 2., p. 2-8, 2-9.) Then he attempted to draw parallels between (i) distribution-only electric companies and (ii) electric utilities recently divested from state ownership in Great Britain and the restructured telephone industry in the United States to support his opinion that investors will demand more return from a distribution-only UDC. We see no meaningful comparison between U.K. electrics and U.S. electrics, nor do we see a meaningful relationship between the deregulation of the telephone industry and the deregulation of the electric distribution industry based on the evidence presented by PG&E. It is difficult to understand why the U.K. capital market and the U.S. telephone market are reasonable proxies for California electric companies, but the U.S. capital markets of electric companies and gas companies are not.

ORA's expert said in regard to competition "this has been a hotbed of investor interest, particularly utility investor interest for three or four years. So if the financial models work right, they will incorporate investors' expectations of the risks associated with any source, including competition. So I don't think the fact that there may be competitive risk requires any adjustments in the models because the investors have already incorporated that into their thinking." (Tr. Vol. 10 p. 12, 92-93.)

On balance, we agree that no basis points should be added to or subtracted from a financial model to account for subjective perceived changes in risk for a distribution-only electric utility. Electric utility restructuring has been well known in California and in the United States since at least 1994. California has taken the lead and other states are following, as is the federal government. Investors are quick to react to changes, and potential changes, in the market place. We have every reason to believe that the financial community has factored into its activities its expectations regarding restructuring. Changes in economic expectations are usually reflected immediately in financial markets; four years is more than enough time to reflect competitive risk. The commentators - Moody's, S&P - and the public pronouncements of the experts testifying in this proceeding are proof of that. At present we will not modify our ROE finding for a distribution discount or premium. However, as electric restructuring unfolds, we anticipate investors expectations may also change. Therefore, it would be appropriate to reevaluate the risk associated with the UDC no later than the 2002 cost of capital.

IV. Financial Modeling Issues

Apart from the UDC risk adjustment, the financial modeling issues in this case are essentially the same as they have been in past cases. The major areas involved in financial modeling are:

1) What is the right composition of the group of companies used as comparables to the UDC?
2) Which cost of capital model should be used? The discounted cash flow model (DCF) single stage or multi-stage? The risk positioning models such as the capital asset pricing model (CAPM) or the empirical CAPM (ECAPM)?
3) What are the appropriate data inputs for the various models, to wit, the growth rate for the DCF model; the risk free rate and the market risk premium for CAPM; the beta of comparable groups; etc?

The parties' modeling presentations offered a wide range of responses to those questions, which, as PG&E says, is very confusing. Each modeling input was the subject of debate and all were tempered by judgment.

A. DCF

The DCF method attempts to measure the cost of equity by assuming that the market price of a stock is equal to the present value of all future dividends that shareholders expect to receive. To implement this method a major simplifying assumption is made: the future is divided into one or more periods (stages) of differing lengths; the dividend growth rate may differ for each of the periods. The industry needs to be sufficiently stable to make reasonably accurate forecasts for the period(s) involved. A single-stage DCF model considers the entire future as one period with an infinite number of years. A multi-stage DCF model breaks up the future into multiple periods, not necessarily of the same number of years.

The parties which utilized the DCF model and their resultant estimates of the cost of equity are shown in Table 3.

Table 3

Discounted Cash Flow - Cost of Equity

PARTY	SINGLE STAGE	MULTI-STAGE	REFERENCE
PG&E	8.7	9.3	Ex. 1 ALK-7 2T.24-26
SDG&E	11.50	--	O.B. p. 7
FEA	8.8 - 10.2	--	Ex. 16 p. 30, 50
C-K	--	10.32	Ex. 23, RJC-1, p. 2
ORA	--	8.95	Ex. 14, p. 4a

PG&E asserts that because of the current instability in the electric industry "DCF results are nonsense" (O.B. p. 18). SDG&E's witness finds that his DCF result supports his recommended range for ROE of 11.30% to 12.50% (O.B. p. 6). FEA, C and K, and ORA all support their DCF results as falling within their recommended overall ROE.

The problem all parties confronted was how to construct financial models generally acceptable to the Commission in the new unbundled environment. One answer was to use a proxy group or proxy groups of companies (most likely utilities) with risk corresponding to the electric distribution function. It was agreed that there are no pure play domestic electric distribution utilities upon which to construct a sample; the construction of sample groups provided much controversy. To cite all of the methods of each expert and the reasoning behind their choices, and each expert's criticism of the choices of the other experts would only add confusion to what is always a complex analysis. To show the variety of proxies used by the witnesses, we will cite only the method used by FEA's expert.

FEA's witness rejected the use of the U.K. utilities, and instead relied on the samples of electric utilities developed by PG&E's and Edison's experts. He eliminated companies that were subject to this proceeding, and companies considered by Edison's witness to be generation companies. He limited his group to companies followed by Value Line, and excluded companies which arguably could be considered to be in financial distress. He also used natural gas distributors in his analysis. Starting with the combined sample of all three utility witnesses, he eliminated companies which Edison's witness considered to be transmission companies, and eliminated companies which SDG&E's witness considered to be involved in acquisition activity or were not predominately gas distributors. As checks on his estimates based on the sample of electric distributors and natural gas distributors, he worked with samples of electric generators and transmission companies. The focus of his analysis was on those groups which approximate electric distribution.

The other experts were equally exacting in composing their proxy companies. It would serve no useful purpose, in our opinion, to chose one proxy group or another as a standard. What is most interesting in the DCF analysis is the closeness of result (except for SDG&E) when the "distribution adjustments" are eliminated. Rather than a spread from 8.64% to 12.1%, we have a more reasonable spread from 8.7% to 10.32%.

B. CAPM

The essential inputs to the CAPM are the risk-free interest rate, the premium that a security of average market risk commands over the risk free rate (market risk premium or MRP), and the risk of a particular company or business relative to the risk of the market (beta). Beta is multiplied by the MRP to obtain the business-specific risk premium. The debate between the parties over CAPM inputs primarily concerns different input estimates for beta and the MRP. The parties recommendations are:

Table 4

PARTY	CAPM	REFERENCE
PG&E	8.30 - 10.3	Ex. 1 ALK 9 (p. 2T 31-34) ALK 10 (p.2T-35)
EDISON	11	Ex. 10 p. 33-34
SDG&E	11.35	O.B. p. 7
FEA	9.52 - 11.0	Ex. 16 p. 48
C-K	10.69 - 10.82	Ex. 23, Sch. RJC-2
ORA	9.31	Ex. 14 p. 20

Table 5

PARTY	MARKET RISK PREMIUM OVER LONG TERM TREASURY	REFERENCE
PG&E	8.5 (Over T-bills)	Ex. 1 ALK 9 (p. 2T 31-34)
EDISON	7.5	Ex. 10, A-2
SDG&E	7.8	Ex. 7, JVW-26
FEA	7.8	Ex. 16 p. 45-50

C-K	7.8	Ex. 23 p. 13
ORA	5.5	Ex. 14 p. 19

One of the main sources of MRP is the Ibbotson Associates data, which shows 9.2 percent average premium of stock returns over Treasury bills from 1926 to 1997. Treasury bills are short-term securities, typically 3 months. Treasury bonds are typically 20- to 30-year securities. The risk premium for the post WWII period, 1947-1997 also is 9.2 percent over Treasury bills. Without the impact of the recent bull market, the Ibbotson MRP over T-bills has been close to 8.5 percent. PG&E's witness used the 8.5 percent MRP over T-bills.

SDG&E's witness and FEA's witness have utilized the Ibbotson MRP over Treasury bonds of 7.8 percent in their CAPM modeling. Edison's witness developed a MRP of 7.5 percent over T-bonds.

PG&E, SDG&E, and FEA are consistent in how their MRPs are developed. All three used well-established data series, to wit, 1926 to 1997 and/or 1947 to 1997 from Ibbotson. All three also rely heavily on the MRP from Ibbotson's arithmetic averages to estimate the expected return on the market.

ORA's witness discussed a number of topics that can bear upon MRP development. He provided an array of different data periods: 1802-1997, 1926-1997, 1951-1997, and 1971-1997. He introduced the concept of geometric averaging of market returns as opposed to arithmetic averaging. He referenced literature which indicates that the future MRP should be lower than historical MRP results. He believes the large number of data smooth out historical aberrations and capture much historical and financial information. After considering these data, he adopts a MRP over Treasury bonds of 5.5 percent and a MRP over Treasury bills of 7.5 percent. ORA's choice of MRP accounts for a substantial portion of the difference between ORA's CAPM results and the CAPM results of the other parties.

The evidence is persuasive that MRP should be based on an historical record that reaches back no further than 1926. Data from the 19th century is too remote in time and relevance. We need not determine whether geometric averaging is superior or inferior to arithmetic averaging when seeking a market risk premium. ORA's witness considered both, but relied on neither. He looked at all the data to draw his conclusion. On the evidence presented, we are most comfortable with an MRP of 7.8%.

Another critical input for the CAPM and related models is the relative risk measure for electric utility companies. That risk measure is the "beta" of the stocks in question, or the measure of the systematic risk of the stock. Beta measures the extent to which a stock's value fluctuates more or less than the average fluctuation of the market. The theory behind beta is that risks that cannot be diversified away in large portfolios are more important for rate of return than risks which can be eliminated by diversification. A stock with a beta of .5 will tend to move 5 percent when the market moves 10 percent. A stock with a beta of 2 will tend to move 20 percent when the market moves 10 percent.

Betas are estimated from actual stock returns using standard statistical techniques. Although betas can and do vary depending on factors such as the time period and the choice of monthly or weekly returns, the main beta-related controversy in this case is whether adjusted or unadjusted betas should be used.[5] Adjustment of beta essentially is designed to correct for a

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[5] The estimate of beta first estimated by standard statistical techniques is called the "raw" beta. To adjust beta, this raw value is either increased or decreased according to the particular method of adjustment.

perceived (by some experts) tendency for low beta estimates to be smaller than the true beta values, and for high beta estimates to be higher than the true values.

The parties to this case used a variety of different sources for their electric utility betas. Edison's and SDG&E's witnesses used the Value Line reported betas for each selected proxy group, which are adjusted. PG&E's witness used betas adjusted with the Merrill Lynch method. FEA's witness used both the Value Line adjusted betas and the S&P unadjusted betas. ORA's witness used the Dow Jones unadjusted betas.

None of the experts in this case contest the fact that estimates of beta are subject to error. In his book, ORA's expert states that beta is always estimated with error. Similarly, Edison's expert testified that true beta cannot be captured and analyzed scientifically. The controversy concerning adjusted versus unadjusted betas has generated a huge academic literature on how to improve the estimates of beta. We are not going to attempt to ascertain the true method for determining beta as applied to ROE. We accept that each expert used his best judgment regarding beta to arrive at his recommendation. We prefer to apply our judgment to the results achieved by the expert witnesses rather than make a futile attempt to reconcile the positions. Considering the evidence regarding CAPM we are satisfied that a range of 9.52% to 11.35% is reasonable.

C. ECAPM

PG&E's expert testified that the empirical capital asset pricing model (ECAPM) is based on a body of research that can be used to improve the accuracy of the CAPM to estimate the cost of capital and should be accepted by the Commission in this case. He said the CAPM is one of the most common risk positioning models based on beta. Research, however, has established that CAPM does not perfectly capture the relationship between risk and stock returns. He said that empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premia than predicted by the CAPM and high beta stocks tend to have lower risk premia than predicted. Thus, there was developed a more robust versions of the models. One such model, based on empirically determined adjustment factors, is an enhancement to the CAPM, the empirical CAPM.

PG&E's witness used the ECAPM to estimate the cost of capital. He started by taking the results based on the empirical finding that risk premia are related to beta, but are not as sensitive to beta as the CAPM predicts. He then adjusted the CAPM upward to reflect the empirical findings. Edison's witness also employed the ECAPM to develop his estimates of return differences. Both contend that since ECAPM more correctly captures the sensitivity of the cost of capital to beta, the Commission should consider the ECAPM results and should not rely solely on the CAPM's less accurate ability to estimate the cost of capital.

We are not persuaded that ECAPM produces a result that should be considered. Electric utilities in general have low betas. Adjusting betas upward guarantees a higher ROE. As Edison's witness says "Investor return requirements are largely a function of long-term expectations and perceptions of long-term risks." (Edison, Ex 10, p. 38). If betas make sense, then to claim that low-beta stocks tend to have higher risk premia contradicts the efficient market theory. What is certain is that in every example offered by PG&E's expert the ECAPM results produced higher overall cost of capital estimates than the CAPM results. (PG&E, Ex. 1, p. 2E-14.)

D. ATWACC

PG&E's expert states that the after-tax weighted average cost of capital (ATWACC) is the theoretically correct measure of the cost of capital and is used by academic and business finance professionals;.its use provides a mechanism to control for changes in a firm's capital structure. He says that modern financial theory indicates that the cost of capital is constant over a broad range of capital structures. In the past, utility regulation has considered debt to provide ratepayer benefits since interest is tax deductible. However, the cost of equity increases as debt is added, keeping the overall after-tax cost of capital constant unless the company endures financial distress. In essence, this increase in equity cost occurs because the use of debt loads the entire variability in operating earnings on the smaller equity asset base, magnifying the risks to the earnings on the equity subset of assets and increasing the cost of equity. The overall cost of capital is expressed as the after-tax weighted average cost of capital. This cost of capital is independent of a company's actual debt/equity capital structure as long as its structure is within the broad range where cost of capital remains constant.

PG&E argues that the ATWACC provides a sound, accepted way to handle the capital structure issue for the UDC without needlessly debating debt/equity ratios. The ATWACC procedures set forth in PG&E's testimony are in its expert's words "absolutely in accord with textbook principles for making investment decisions as well as the way well-managed companies actually behave." (Ex. 2, p. 2-48.) Nonetheless, PG&E recognizes that the ATWACC is a new concept to the world of utility regulation with which the parties are not yet comfortable. PG&E notes that even SDG&E and Edison need more time to consider the concept. For these reasons, PG&E accepts that the Commission may not want to adopt the ATWACC in this case. PG&E requests that ATWACC may be addressed in future cost of capital cases, or their successor proceedings.

PG&E's expert testified that his analysis put the ATWACC for the bundled electric utility in the 7.25% - 7.75% range. He believes that unbundling and partial deregulation will increase the overall cost of capital by 1.0%. This yields a range of 8.25% to 8.75%, with a point estimate of 8.5%, resulting, at PG&E's book capital structure, in a cost of equity of 13.1%. PG&E's policy witness said that PG&E does not wish to increase its revenue requirement by the recommendation of its expert; rather, PG&E requests an ATWACC of 8.0% and an ROE of 12.1%.

ORA argues that PG&E has not met its burden to show that the ATWACC is a model useful to this Commission. ORA observes that whatever simplicity the model represents is immediately dissipated by its adjustments and recomputations to account for perceived omissions, not captured by the formula. Further, ORA asserts that PG&E has not met the burden of proof associated with a methodology that is new and untried in any regulatory jurisdiction. ORA asks: Is it robust? Does it yield reasonable results over time? How does utility ATWACC compare to the broader market? There is no historical data for electric or gas utilities for the Commission to assess how ATWACC would perform under a range of economic conditions, nor is there comparative information to gauge how utilities compare to the broader market.

We will not reject a proposal merely because it is new, nor need we wait for other Commissions to pronounce upon it. But the evidence presented does not give us confidence that it is more accurate or useful than other methods with which we are comfortable. As we consider the ATWACC, as presented in this proceeding, its proponent adds one full percentage point for subjective competitive risks which we cannot find, and it produces an ROE that its sponsor, PG&E, prudently reduces. If we eliminate the one percent competitive risk adjustment the ROE becomes 11.1%, a much more reasonable estimate.

E. Interest Rates

In this case, the parties agree that the Treasury rates for bonds and bills represent the normal risk-free interest rate benchmarks. The DRI April 1998 forecast of 30-year T-bonds for 1999 was 5.63%. In October 1998, the DRI forecast for 30-year T-bonds dropped from approximately 5.63 to 4.71 percent. This drop occurred during tremendous turmoil in foreign markets, when investors were fleeing to the safety of U.S. government backed securities and Treasury rates fell to unusually low rates. As a consequence, Treasury rates were not at equilibrium with other securities. Double A rated utility and municipal bonds had not experienced as steep a decline as Treasuries, especially the 30-year bond. Forecasts of AA utility bonds moved from 6.59% in April 1998 to 5.87% in October 1998.

PG&E and SDG&E are in agreement that we should consider the current estimate of interest rates when making our final decision, but should also consider the anomalous behavior of interest rates due to recent turmoil in the global financial markets. PG&E maintains that we should not implement an interest rate adjustment that exceeds 50 percent of the change in the benchmark Treasury between the time of the utilities' filings and the most recent benchmark Treasury in the record. PG&E is concerned that we would make a mechanical adjustment to reflect the Treasury interest rate change in the modeling results. They recognize that the current benchmark interest rate information is very important to our cost of capital determination, but they say that constant updating of all the model assumptions simply is not possible. They recommend that the most even-handed way to reflect the post-modeling interest rate change without updating other assumptions may be to make only a partial interest rate adjustment. In PG&E's 1997 cost of capital D.97-12-089, we stated "Our consistent practice has been to moderate changes in ROE relative to changes in interest rates in order to increase the stability of ROE over time" (mimeo, p. 12). Consistent with this statement, the Commission has had a practice of only adjusting rate of return by one half to two thirds of the change in the benchmark interest rate (D.94-11-076, 57 CPUC2d 533).

SDG&E recognizes that we must take changed interest rates into account, but does not recommend a numerical adjustment; it advises caution because of the volatility of interest rates. Edison make no recommendation.

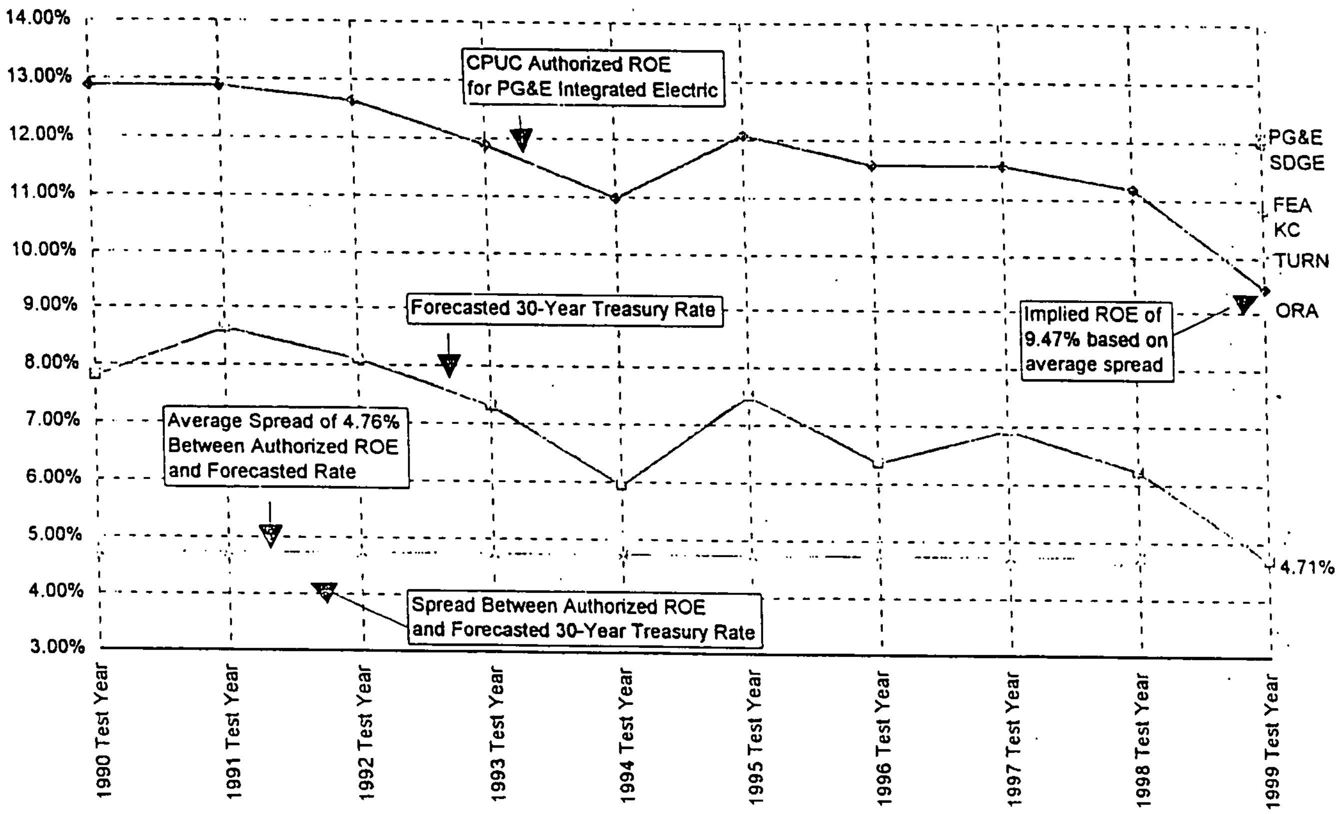
ORA asserts that we should make a 1- to -1 adjustment between a change in interest rates and the change in investor expectations. C and K adopted a 60 basis point reduction. Their previous range of ROE of 10.7 to 10.9% drops to 10.1 to 10.3% with a recommended value of 10.2%. TURN recommends a .7 adjustment. FEA also recommends an adjustment but has not quantified it.

In prior decisions we have factored into our calculations changes in interest rates occurring after the parties have presented testimony. (D.94-11-076, 57 CPUC2d 533, 550-51; D.95-11-062, 62 CPUC2d 480, 494; D.97-12-089, p. 12). We will do the same here. We agree that interest rate changes and investor expectations do not move in lockstep. ORA makes a compelling argument in its comments that the proposed and alternate decisions moderated the change in interest rates in a manner that departs from historical practice. We have reviewed the adjustments in past cost of capital proceedings and find that in circumstances where the interest rate spread was much more significant than in this case (both upwards and downwards), adjustments ranged from 50 to 70%, with the largest adjustment applying when interest rates increased. As we view current conditions of low inflation and a stable economy, contrasted with the recent drop in the rate of the 30-year T-bond and AA utility bonds, we believe an adjustment of .6 of the decline in interest rates is warranted. We are convinced that we should not depart from past practice of adjusting model results based on changes in AA utility bond rates. As SDG&E points out in that comments, utility bonds were trading at more stable levels and the Commission has not previously relied on 30-year T-bond rates. The drop was 72 basis point for AA utility bonds; we will use 43 in our calculations.

F. Commission Recorded Risk Premium

A useful benchmark to assure that we do not act inconsistently in determining ROE is the recorded risk premium between the Commission's authorized equity returns for the integrated utilities and the interest rates forecast at the time of authorization. This benchmark was put into the record by PG&E. (Exh. 5.) As reflected in ORA's summarization, the average spread between authorized equity returns for the utilities and the 30-year T-bond rate between 1990 and 1998 was 4.76%. It is summarized in the following chart:

Table 6
CPUC Authorized Return on Equity
Spread Over Forecasted 30-Year Treasury Rate
1990-1998



This chart shows the correlation between interest rates and return on equity. We tend to increase ROE when interest rates are forecast to rise, and decrease ROE when interest rates are forecast to fall. This is no more than a reflection of the opinion of every expert testifying in this proceeding: investors always consider the opportunity cost of investments. All parties (except, perhaps Edison) agreed that their recommendations for ROE would be adjusted for a later change in interest rates forecast. The 30-year Treasury bond interest rate used by the experts in their original testimony averaged 5.94%.[6] The April 1998 DRI forecast of 30-year Treasury bonds and AA utility bonds were 5.63% and 6.59% for 1999 respectively. The corresponding October 1998 DRI forecasts are now 4.71% and 5.87%. We will consider this reduction when adopting our ROE. We caution the parties - our use is not a computation, but a judgment.

V. Rate of Return

The rate of return (ROR) is the amount earned, or allowed to be earned, by a utility, expressed as a percentage of the utility's rate base. In our proceedings it is calculated as weighted average of the utility's cost of capital: the cost of long-term debt, the cost of preferred stock, and the return on common stock equity (ROE). In this proceeding there is little dispute over the debt and preferred stock portions of the cost of capital.[7] It is the ROE that captures our attention.

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[6] Exh 6, p. JVW-29; Exh 10, p. 34; Exh 16, p. 41 & 47; Exh 23, p. 13; ORA Opening Brief, p. 22.

[7] With the exception of ORA, there was no dispute over the cost of debt and preferred stock. ORA's derivation of the cost of debt and preferred stock resulted in slightly different costs than recommended by the utilities, see for example Exh. 13, pp. 1-5. ORA also believes Edison's cost of debt should be adjusted to reflect directives in the rate reduction bond decision, D.97-09-054, see Exh 13, p. 15. The maximum difference

Footnote continued on next page

A. ROE

The ROE is the most contentious issue in a cost of capital proceeding. All commentators have emphasized the need for the decision maker to apply judgment to whatever financial models are used, and those commentators have been forthright in rendering their judgment on the reasonable ROE. We begin our analysis with the financial models proposed by the parties in light of our finding that we can find no discernible risk difference between an unbundled electric utility and an integrated electric utility. Stated another way, we believe that whatever the risk differences, they have been noted by investors and are incorporated in the financial models.

We approach the financial models gingerly. We cannot repeat too often our concern.

> "We have often expressed our opinion that the financial models employed in our cost of capital proceedings should not be determinative and must be tempered with a great deal of judgment. (38 CPUC2d 233, 238 (1990).) The Discounted Cash Flow (DCF) Model, Risk Premium (RP) Model, and Capital Asset Pricing Model (CAPM) cannot be relied upon exclusively to develop a particular ROE, but may be helpful in developing a range of reasonable values. (Id.) 'Our consideration of these three models has always been accompanied with considerable reservation.' (Id.) First, '[t]he application and interpretation of these financial models may not accurately reflect all of the intricacies of the financial market.' (26 CPUC2d 392, 426 (1987).) Second, '[a]lthough the quantitative financial models are objective, the results are dependent on subjective inputs.' (D.91-11-059 mimeo at p. 25.) We have also recognized that the CAPM and RP models currently provide higher results than does the DCF model (33 CPUC2d 233, 238 (1990)). This

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between ORA's proposal and the utilities is 10 basis points, see Exh 13, pp. 1-7.

continues to be true in this year's proceeding." (D.93-12-022, 52 CPUC2d 390, 406.)

What stands out immediately in the DCF and CAPM tables (above, pp. 40, 42) is the wide disparity in result. The DCF ranges from 8.7% to 11.5%; the CAPM from 8.30% to 11.35%. This disparity is based on the choice of proxies and inputs used by the experts. Much of the hearing time was consumed by the utility experts' criticizing the modeling inputs of the non-utility experts and vice versa. We see no useful purpose in attempting to resolve differences in modeling inputs because there is no satisfactory resolution that commands the approbation of either the experts or the investment community.

When we look at each party's ROE recommendation based on that party's financial model results without considering the party's adjustment for unbundling we get a more manageable value.

Table 7

For PG&E		**For SDG&E**		**For Edison**	
PG&E	11.1	SDG&E	11.0[8]	Edison	11.6
FEA	10.85	FEA	10.85	FEA	10.85
C-K	10.8	C-K	10.8	C-K	10.8
ORA	9.13	ORA	9.13	ORA	9.13
TURN[9]	9.85	TURN	9.85	TURN	9.85

[8] SDG&E's testimony is confusing on whether SDG&E recommended a 20 or 100 basis point adjustment. We do not adjust the figure in Table 7 after our review of the record because SDG&E did not clearly state its position.

[9] TURN did not use financial models to support its recommendations. We use the midpoint of its recommended range of 9.5% to 10.2% for each utility.

The above values should be adjusted by the October 1998 DRI forecastfor AA utility bonds. However, the forecast should not be applied 1 to 1, but as discussed in Section II E, we will apply a .6 ratio (Table 8).

Table 8

For PG&E		**For SDG&E**		**For Edison**	
PG&E	10.67	SDG&E	10.57	Edison	11.17
FEA	10.42	FEA	10.42	FEA	10.42
C-K	10.37	C-K	10.37	C-K	10.37
ORA	8.70	ORA	8.70	ORA	8.70
TURN	9.42	TURN	9.42	TURN	9.42

A final consideration is the magnitude of the change, regardless of a cold reading of the numbers. A precipitous drop would be unfair to investors and would send the wrong message to all stakeholders - the ratepayer, the utility and its employees, and the investment community. The long-term financial health of a utility should not be hostage to sudden fluctuations in the market. As we have expressed the view in the past, "We have moderated ROE increases during inflationary periods, and have declined to lower ROE abruptly when inflation is low." (D.93-12-022 at 41, 52 CPUC2d 390, 411, D.92-11-047 at 103, 46 CPUC2d 319, 370.) Therefore, we cannot adopt the recommendations of ORA or TURN.

Considering the evidence, and based on our judgment, we find that the reasonable ROE for PG&E and SDG&E is 10.6%.[10] Our analysis of the model results also indicates that we should adopt an ROE of 10.6% for Edison, all else being equal. We must now evaluate whether PG&E, SDG&E, and Edison have the same circumstances by addressing the merits of Edison's argument that to reduce its ROE and undo the cost of capital trigger mechanism authorized in its PBR decision is unfair and biased because the PBR mechanism sets and adjusts its cost of capital through 2001.

There is no dispute, that, although SDG&E has a PBR mechanism, its rate of return is the subject of review and adjustment in this cost of capital proceeding. There is also no dispute that PG&E's rate of return is the subject of this proceeding, in that it does not currently have a PBR mechanism. However, in late 1996 the Commission concluded its review of a comprehensive PBR procedure for Edison (D.96-09-092). The PBR established Edison's base rates for nongeneration and distribution service for the period 1997 through 2001. The Commission excluded consideration of generation costs and anticipated removal of transmission costs to FERC jurisdiction. Edison's base rates were fixed during the PBR period, subject to adjustment for inflation, assumed levels of increases in productivity, and a cost of capital trigger mechanism to track changes in

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[10] All three utilities have cited our recent Southwest Gas Corporation (SGC) decision (D.98-09-030 in A.98-05-003) for the fact that there we authorized an ROE of 11.35%. From that they argue an ROE of less than 11.35% would contradict our most recent holding. The utilities' confidence in D.98-09-030 is misplaced. That decision merely continued without modification an ROE adopted in late 1994, pending SGC's next general rate case, expected in 1999. We noted that "the trend of Commission authorized returns on equity has been downward." (Id. p. 3.) D.98-09-030 was issued ex parte, without protest.

economic conditions affecting Edison's return on equity. Cost savings achieved by Edison under the PBR are shared with customers to provide an incentive to achieve efficiencies to lower rates.

Edison asserts that a key element of the PBR mechanism is the cost of capital trigger mechanism. The trigger mechanism governs Edison's return on common equity which is the benchmark for net revenue sharing with Edison's customers between 1997 and 2001. The trigger mechanism included a procedure to update the return on equity to reflect changes in economic conditions. The PBR mechanism was implemented by Commission Resolution E-3478 and became effective January 1, 1997.[11] The Commission accepted Edison's PBR rates based on the adopted 1997 return on equity, capital structure, and preferred stock and embedded debt costs. These facts makes Edison's circumstances distinct from those of PG&E and SDG&E.

Edison contends that changing its ROE in this proceeding would completely undo the cost of capital trigger mechanism by changing the balance of risks that was adopted in its PBR. The adjustments proposed by ORA and TURN reflect unbundling discounts and updates for changes in economic conditions which have occurred since the PBR was adopted. In Edison's opinion, those recommendations violate both the letter and the spirit of the Commission's PBR decision because the PBR mechanism already contained procedures to update the cost of capital based on changes in economic conditions.

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[11] Resolution E-3478, Finding 8, p. 7 ("Edison should modify its Cost of Capital Trigger Mechanism to reflect the authorized return on rate base. With that adjustment, it is reasonable to approve the Cost of Capital Trigger Mechanism for adjusting nongeneration base rates.")

Because we conclude that no risk premium is warranted as made clear in our discussion above, our recommended changes to the ROE are primarily based on the changed market conditions since the last cost of capital proceeding. Edison's trigger mechanism is specifically designed to adjust for these types of changes. We must ask ourselves whether it is appropriate to modify one element of a balanced PBR mechanism based on changed market conditions, especially when that mechanism specifically takes such changes into consideration. After much consideration, we agree with Edison that, at this point in time, it would be inappropriate to modify its ROE rather than continuing to allow the trigger mechanism to operate. Had we concluded that a risk premium, up or down, was appropriate as a result of unbundling, we would likely have reached a different conclusion. Therefore, we will not adjust Edison's ROE of 11.6%.

Interest coverage for each utility based on their individual capital structure and cost of preferred stock and long-term debt (updated in Exh. 88) and adopted ROE is:

Table 9
Pre-Tax Interest Coverage

PG&E	3.8x
SDG&E	4.2x
Edison	3.74x

This coverage is more than adequate and should not negatively affect the utilities' bond ratings.

B. Debt, Preferred Stock, and Rate of Return

The capital structure and costs of debt and preferred stock of the utilities have not been contested in this proceeding.[12] Consequently, we will adopt PG&E and SDG&E's proposed capital ratios and costs, with updated information from Exh. 88. PG&E's capital structure and costs are the same for its electric distribution operations and gas operations. SDG&E's capital structure and costs are also the same for its electric distribution operations and gas operations. We make no change to Edison's capital structure and costs of debt and preferred stock which were fixed in Edison's PBR mechanism.

[12] With the exception of ORA, there was no dispute over the cost of debt and preferred stock. ORA's derivation of the cost of debt and preferred stock resulted in slightly different costs than recommended by the utilities, see for example Exh. 13, pp. 1-5. ORA also believes Edison's cost of debt should be adjusted to reflect directives in the rate reduction bond decision, D.97-09-054, see Exh. 13, p. 15. The maximum difference between ORA's proposal and the utilities is 10 basis points, see Exh 13, pp. 1-7.

Table 10
Capital Structures

PG&E			
	Capital Ratio	Cost	Weighted Cost of Capital
Debt	46.20%	7.09%	3.28%
Preferred	5.80%	6.55%	0.38%
Common Equity	48.00%	10.60%	5.09%
Total	100.00%		8.75%

SDG&E			
	Capital Ratio	Cost	Weighted Cost of Capital
Debt	45.25%	6.87%	3.11%
Preferred	5.75%	7.76%	0.45%
Common Equity	49.00%	10.60%	5.19%
Total	100.00%		8.75%

VI. Gas Distribution Utility Return on Equity and Rate of Return

We are also determining the rate of return for PG&E's and SDG&E 's gas local distribution company (LDC). All parties agree that determining ROR for an LDC is significantly different from that of the UDC because there is no dispute over a risk adjustment. All agree that the existence of public companies with business risks comparable to the natural gas distribution business and the relative stability currently prevailing in the natural gas industry simplify the cost of capital estimation procedure relative to what the Commission faces for the

UDC. Therefore, the issues for the LDC rate of return are limited to financial modeling issues tempered by judgment.

Just as there was controversy with financial modeling to estimate the UDC cost of capital, the process of modeling the cost of capital for the LDC has led to controversies about inputs and assumptions, models and comparable groups. For instance, the parties modeling the LDC have developed different proxy groups, differences in growth rate assumptions for the DCF model, the same controversies over what MRP should used, the same debate over interest rate adjustments to the modeling results, and the same arguments over adjusted versus unadjusted betas. As usual, judgment is critical.

The parties' choices of comparable gas distribution companies is not determinative of the cost of capital for the LDC. Each of the parties to this case used different comparable groups for the LDC analysis. SDG&E 's witness used the Value Line group of local natural gas distribution companies. PG&E's witness started with the Value Line natural gas distribution category and then applied selection criteria to identify those companies which better approximated "pure plays" on the LDC. He eliminated companies in financial distress or involved in merger activities. ORA's witness used PG&E's comparable group. FEA's witness used a combination of ORA's and SDG&E 's comparable groups. C and K used a broad group of companies. All of these comparable groups are reasonable proxies to use for modeling in this case.

The parties who used the CAPM for modeling the UDC also used it for modeling the LDC. And the differences in the parties' inputs and assumptions for the CAPM electric utility modeling are the same for the parties' CAPM gas distribution modeling. Thus the questions of how to adjust the modeling results for subsequent changes in the risk free rate, which MRP should be used, and whether the gas proxy group's beta should be unadjusted or adjusted are the same for LDC modeling as they are for UDC modeling.

TURN did not perform financial modeling for the LDC. Instead TURN's witness stated his belief that the business risk differences between electric and gas distribution operations are small because (1) major determinants of business risk, the state of the economy, and California regulation, are largely the same for both, and (2) the Commission in the past has authorized only small ROE differences between electric and gas utilities. He then recommended an ROE for the LDC of 10 basis points over his recommendation for the UDC.

The issues involving the LDC in this case are fewer than for the UDC because there is no need to develop a restructuring adjustment. Otherwise, all the other financial modeling issues are present and in controversy.

For convenience, we repeat the recommendations found in Tables 1 and 2.

Table 1
ROE RECOMMENDATIONS

Recommendations A/			
Party	**Electric**	**Gas**	**Basis Points for Electric Distribution Risk (included in ROE)**
PG&E	12.10	12.10	+ 100
SDG&E	12.00	12.00	+ 20 to + 100
Edison	11.60	NA	0
FEA (all)	10.85	10.85	0
Knecht-Czahar (all)	10.80	10.80	0
Weil-TURN-PG&E	9.00	9.10	- 30 to - 124
-SDG&E	9.10	9.20	- 30 to - 124
-Edison	8.80	NA	- 30 to - 124
ORA (all)	8.64	9.32	- 49

A/ Before adjusting for the October 1998 DRI forecast.

Table 2

Current Authorized ROE		
Party	**Electric**	**Gas**
PG&E	11.20	11.20
SDG&E	11.60	11.60
Edison	11.60	-
CPUC Historical Benchmark[B]/	9.47	9.47

[B]/ October 1998 DRI forecast 30 year T-Bonds 4.71 + 4.76 (the average Commission authorized risk premium as computed by ORA).

We do not understand why PG&E and SDG&E recommend an ROE for their LDC operations at the same level as their ROE recommendation for their UDC operations. As shown on Table 2, PG&E's and SDG&E 's current authorizations are the same for integrated electric utility operations and LDC operations. In D.93-12-022 we eliminated differences in ROE between major electric and gas companies (D.93-12-022, mimeo., 43, 52 CPUC2d 390, 412). That has been continued for PG&E (D.97-12-089) and SDG&E (D.96-11-060). We see no reason to deviate from that policy. SDG&E in its brief says "the risks associated with SDG&E 's electric distribution business will exceed the risk of the local gas distribution business" (SDG&E , O.B., p. 7). Yet SDG&E seeks the same ROE. PG&E's expert is of the opinion that LDCs represent a reasonable proxy or benchmark for stand-alone UDCs (PG&E, O.B. p. 43), that is, the risks for the LDC are similar to the risks of the UDC. He would add two or three percentage points to the LDC's cost of capital, as he did for the UDC. As we have rejected that premium for the UDC, a fortiori, we reject it for the LDC.

Having found no adjustment to be necessary for the ROE for the UDC, and applying our policy of parity between gas and electric companies, we find that the reasonable return on equity for PG&E's and SDG&E 's LDC operations is 10.6%. The rate of return for the LDC is the same as for the UDC.

VII. Rate Base and Revenue Requirement

The revenue requirement effect of the reduced return on equity and reduced rate of return is based on 1) for PG&E, the estimates of PG&E and ORA from PG&E's general rate case A.97-12-020, Exh. 474 and GRC briefs, and 2) for SDG&E, the rate base established in its distribution PBR D.98-12-038. We emphasize that the revenue requirement effect for PG&E is an estimate which will change when the distribution rate base for the utility is finally determined. The projected rate base for each utility is:

Table 11
Rate Base

	Electric	Gas
SDG&E	$1,385,722,000	$452,863,000
PG&E		
PG&E Est.	$7,003,639,000	$2,175,595,000
ORA Est.	$5,899,013,000	$2,010,056,000

Applying the rate of return found reasonable, we estimate the annual revenue requirement is reduced as follows:

Table 12

Reduction in Revenue Requirement

	Electric	Gas
SDG&E	($14,585,000)	($4,779,000)
PG&E		
PG&E Est.	($46,280,000)	($14,500,000)
ORA Est.	($38,980,000)	($13,396,000)

VIII. Implementation of Rates

The scoping issues identified for this case include the following two questions:

(1) What revenue requirement mechanisms are necessary and should be established to reflect authorized cost of capital on January 1, 1999, if this proceeding, or related ratemaking proceedings are delayed beyond that date?

(2) How should ratemaking issues related to cost of capital be determined in future ratemaking proceedings?

In regard to the first question, the method to reflect authorized cost of capital in revenue requirement is set forth below for each utility. The second question is more troublesome given our finding that it is premature to incorporate an unbundling risk premium, up or down, at this time. We find that it is appropriate to revisit this question for all utilities no later than the 2002 cost of capital proceeding.

A. PG&E

PG&E recommends that we coordinate this cost of capital proceeding with the results of operations and rate base adopted in its 1999 general rate case. It believes placing the 1999 GRC and the 1999 COC rate changes into effect together would be optimal because the rate changes could then be consolidated, and proliferation of different rates at different times with different costs of capital applied to different rate bases could be avoided. Therefore, PG&E maintains that the 1999 cost of capital should go into effect at the earlier of (a) the effective date of interim rate relief in its 1999 GRC or (b) the effective date of the rate change in its 1999 GRC final decision if no interim relief is granted. Interim relief was granted as of January 1, 1999 (D.98-12-078 in A.97-12-020).

In order to place PG&E's proposal in effect, we will issue an order which provides that PG&E's 1999 cost of capital will go into effect as of January 1, 1999.

B. SDG&E

SDG&E recommends that necessary rate changes should be made effective shortly after the final decision in this proceeding, allowing sufficient time for compliance filings. We agree.

C. Edison

Because we do not modify Edison's cost of capital, but instead retain its trigger mechanism, Edison's rates are not affected by this order.

IX. Alternate Decision

This alternate was issued for comments. We have reviewed the comments filed and made appropriate changes throughout the text.

Findings of Fact

1. The Commission in 1994 embarked on a process to restructure the electric services industry in California.

2. The California State Legislature established the framework for restructuring the California electric service industry in AB 1890.

3. The Commission adopted a comprehensive PBR for Edison in D.96-09-092, including a cost of capital trigger mechanism.

4. The major electric utilities, Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company have undergone fundamental changes in their operations as a result of restructuring.

5. The process of restructuring is ongoing and will continue to change the way in which utility operations subject to the Commission's jurisdiction are regulated.

6. The operations of the utility distribution companies are subject to regulation by the Commission.

7. The returns on the generation function of the former integrated utility are set by either market forces or by Commission decisions and legislative provisions.

8. The transmission function of the former integrated utility is regulated by the Federal Energy Regulatory Commission.

9. The remaining operations of the UDC consist of more than distribution operations.

10. The UDC is not a pure distribution company and will not become a pure distribution company for the foreseeable future.

11. The Commission should consider the risks associated with remaining functions of the UDC when it determines a reasonable return on equity.

12. In D.97-08-056, the Commission ordered the major electric utilities to file applications in this proceeding to consider unbundling cost of capital.

13. The evidence in this case shows that the UDC is neither more risky nor less risky than the former integrated utility.

14. There is no basis for imposing a distribution risk discount or unbundling adjustment on UDC operations; nor is there basis for adding a risk premium adjustment.

15. Gas distribution utilities are similar to electric utility distribution operations.

16. The Commission has historically authorized nearly the same returns for gas and electric utility operations.

17. In prior cost of capital decisions, the Commission did not rely exclusively on model results to determine the authorized return on equity.

18. The financial models employed in our cost of capital proceedings should not be determinative and must be tempered with a great deal of judgment. The DCF model, RP model, and CAPM model cannot be relied upon exclusively to develop a particular ROE, but may be helpful in developing a range of reasonable values. They are useful in establishing a range of required returns to consider in selecting the authorized return and in evaluating trends of investor expectations.

19. SDG&E's changes in revenue requirements resulting from this decision should be allocated to electric rates by class and spread in a manner consistent with the revenue allocation and rate design principles adopted in D.96-06-033 and D.97-08-056. The allocation and rate design principles applicable for gas rates are to be done in a manner consistent with the revenue allocation and rate design principles adopted in D.97-04-082 and as approved in Resolution E-3510.

20. For electric utilities the divestiture of generation and the FERC's regulation of transmission have not altered traditional methods of determining return on equity.

21. The reasonable return on equity, capital structure, cost of capital, and rate of return for the distribution electric utility operations of PG&E, SDG&E, and

Edison are :

PG&E

	Cap Structure	Cost	Wgt Cost
Debt	46.20%	7.09%	3.28%
Pref	5.80%	6.55%	0.38%
Equity	48.00%	10.60%	5.09%
Total	100.00%		8.75%

SDG&E

	Cap Structure	Cost	Wgt Cost
Debt	45.25%	6.87%	3.11%
Pref	5.75%	7.76%	0.45%
Equity	49.00%	10.60%	5.19%
Total	100.00%		8.75%

Edison

	Cap Structure	Cost	Wgt Cost
Debt	47.00%	7.64%	3.59%
Pref	5.00%	6.62%	0.33%
Equity	48.00%	11.60%	5.57%
Total	100.00%		9.49%

22. The reasonable return on equity, capital structure, cost of capital, and rate of return for the gas distribution operations of PG&E and SDG&E are the same as for their electric distribution operations.

23. The return on equity for the unbundled electric distribution operations of PG&E and, SDG&E is the same as for their bundled electric operations.

Conclusions of Law

1. Edison's 1996 PBR decision does not preclude its rate of return from being determined in this proceeding.

2. Because no adjustment is made as a result of unbundling, we will not disturb the operation of Edison's cost of capital trigger mechanism.

3. PG&E's cost of capital should go into effect as of January 1, 1999.

4. SDG&E's cost of capital should go into effect 30 days after the effective date of this order or as part of a consolidated revenue change with A.99-02-029, depending on the timing of the end of the rate freeze.

O R D E R

IT IS ORDERED that:

1. The cost of capital for 1999 of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) are set forth in the Findings of Fact and Conclusions of Law of this decision, and are approved.

2. PG&E's cost of capital should go into effect as of January 1, 1999.

3. If SDG&E's rate freeze ends on or before July 1, 1999, the revenue impacts of this order shall be consolidated with the rate changes resulting from Application (A.) 99-02-029. SDG&E shall file an advice letter consistent with the provisions of the decision in A.99-02-029 to reflect the revenue changes adopted here in. If SDG&E's rate freeze is expected to end after July 1, 1999, SDG&E shall file an advice letter within 5 days of the effective date of that determination, but no later than June 30, 1999, with tariffs consistent with this order. The advice

letter shall go into effect 30 days after it is filed, upon Energy Division determination of compliance.

4. Application (A.) 98-05-019, A. 98-05-021, and A. 98-05-024 are closed.

This order is effective today.

Dated June 10, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
LORETTA M. LYNCH
JOEL Z. HYATT
Commissioners

I dissent.

/s/ JOSIAH L. NEEPER
Commissioner

Appendix A

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(END OF APPENDIX A)