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Proposal for Expanding the ERA's Financial Benchmarking System and Implementing Performance Agreements

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ABBREVIATIONS AND ACRONYMS

ACMI	Average Customer Minutes of Interruption
CAIDI	Customer Average Interruption Duration Index
CES	Central Energy System
ERA	Energy Regulatory Authority
EPRC	Economic Policy Reform and Competitiveness Project
EU	European Union
KPI	Key Performance Indicator
MAIFI	Momentary Average Interruption Frequency Index
OSHA	Occupational Safety and Health Administration
PA	Performance Agreement
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SC	Social Cost
T&D	Transmission and Distribution
USAID	United States Agency for International Development

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EXECUTIVE SUMMARY

The EPRC Project Team has reviewed the ERA's benchmarking system and process currently in use. At the request of the ERA Chairman, the EPRC team has initially focused on financial key performance indicators (KPIs) and performance agreements between the ERA and all licensees.

Financial Benchmarks

The project team recommends that the ERA use additional financial indicators and furthermore that the ERA broaden the range of indicators to cover a standard financial spectrum. The team recommends that the ERA use eight commonly known financial ratios rather than the five financial KPIs currently in use. These ratios are commonly used, internationally, for financial analysis. The ERA staff have informally indicated that this information can be calculated from the information that licensees file with the ERA with some follow up questions to licensees.

Recommended Financial Key Performance Indicators

Indicator	Equation	Measurement Rationale
1. Quick Ratio	Current Assets – Inventory/ Current Liabilities	Liquidity
2. Total Owner's Equity to total Assets (%)	Total Owner's Equity/ Total Assets	Leverage
3. Interest coverage Ratio (times)	Earning before interest and taxes/ Interest Expenses	Coverage
4. Return on Equity (%)	Net Profit/ Total Owner's Equity	Profitability
5. Profit Margin (%):	Net Sales – Cost of goods sold/ Net Sales	Profitability
6. Average collection period (day)	Accounts Receivable/ Average daily sales	Common size
7. Average payable period (day)	Payable Accounts / Net credit purchase	Common size
8. Change is gross sales	(Sales current year/sales prior year) -1	Activity

Performance Agreements

A performance agreement is a legal contract signed by the regulator and the licensee. PA's have been widely used by regulators as a means to monitor and provide consequences for areas of concern for regulators.[1]

[1] Examples of US performance agreements and an agreement under consideration by the Egyptian Regulator are included in Annex D.

The PA shall include specified performance targets and specific consequences for the licensee's performance as measured by selected Key Performance Indicators (KPIs). Thus, a PA provides the ERA with a regulatory tool that provides licensees incentives to improve performance in targeted areas.

The ERA should require licensees to sign performance agreements by amending a company's license. The ERA can use its authority to determine tariff rates to link the performance agreement with financial rewards and penalties, depending on the performance of the licensee.

The EPRC team recommends that, as the first step, the ERA first negotiate and then implement a performance agreement with one licensee. This will resolve any generic problems or issues and will provide the ERA with experience to be used in negotiating performance agreements with other licensees.

INTRODUCTION

This report provides the EPRC analysis and recommendations regarding the financial data used by ERA in its current Benchmarking System as shown in Section I "Financial Benchmarks." Section II of this report provides an overview of Performance Agreements with specific considerations for use by the ERA.

SECTION I: FINANCIAL BENCHMARKS

A. ERA Current Financial Benchmarking System

The ERA currently uses 5 KPIs in its financial benchmarking work:

1. Net Income
2. Current Liabilities
3. Account Receivables
4. Total Cost
5. Sales Revenue

The first three KPIs are used in the ERA's monthly evaluation of companies. All five KPIs are used in ERA's quarterly "ranking" of all 17 major companies and 8 smaller energy companies (see Annex A).

The EPRC team recommends that the KPIs be expanded to:

- provide a broader scope of standard financial categories and,
- rely on standard financial ratios for measuring financial performance. (Illustrated in Table 1 below.)

The EPRC team recommends that ERA consider the following broad categories of financial indicators:

1. Liquidity
2. Coverage
3. Activity
4. Common Size Analysis.
5. Profitability
6. Leverage

A selection of KPIs measuring the above 6 categories will monitor key financial aspects of energy companies. There are several standard indicators for each of these categories, and they are noted below.

Most of the standard financial indicators can be calculated from a company's accounting reports, e.g. balance sheet and income statement. USAID has provided detailed training to the Mongolian energy companies' staff on financial reporting and financial ratios as part of the USAID program to promote use of Uniform System of Accounts, in compliance with International Accounting and Financial Reporting Standards.[2] ERA staff should collaborate with USAID financial experts to assure that financial data and resulting financial ratios are accurately reported.

B. Description of Financial Categories

B.1. Liquidity

A company's liquidity is of key importance to Mongolian energy companies. Liquidity "… is the ability of a company to meet short-term debt out of current assets."[3] Examples of liquidity ratios include:

- Current Ratio – which measures the firm's ability to cover its current liabilities with current assets;

[2] Energy Regulatory Authority of Mongolia, 2005 Annual Report, page 21.
[3] Shim and Siegel, **Encyclopedic Dictionary of Accounting & Finance,** 1989, page 280.

- Quick Ratio – which measures the firm's ability to meet its current liabilities with its most liquid assets; and
- Cash Ratio – This measures the firm's ability to cover its current liabilities with cash and cash-equivalents.

In each of the above cases, if the liquidity ratio is less than 1, the firm is not in good financial standing. If the firm needed to meet its current obligations it would be unable to do so without the liquidation of assets.

B.2. Coverage

Coverage is another key financial variable for Mongolian companies. The ability of companies to service their debt obligations with operating income is measured by the following coverage ratio:

- Interest Coverage Ratio – the firm's earnings (before interest expense and taxes) divided by its interest expense.

The coverage ratio should be well above 1. If it is below 1, the firm's operations are unable to service its debt obligations, which will result in a charge against the retained earnings from prior periods, if any, and possibly the liquidation of long-term assets to avoid a default on the outstanding debt obligation. Since a default by the firm would likely adversely affect the quality of customer service, it is imperative that the regulator monitor the licensee's ability to cover the service of its outstanding debt.

B.3. Common Size Analysis

It is appropriate for the regulator to collect information that measures each licensee's "activity" and comparative analysis. "Common-size" information refers to indicators expressed in percentages of a base. The percentages permit relative comparison among companies of varying sizes. Examples of Common size measurements include:

- The average collection period - The average time period for which receivables are outstanding. Equal to accounts receivable divided by average daily sales, also called collection ratio. There is a positive correlation between the length of the collection period and the resources which companies must set aside for working capital.
- Average Payable period – is defined as the ratio of payable accounts/net credit purchase. Net credit purchasing is the fastest way to finance a firm's operations. However, if the average payable period increases the firm's credit worthiness decreases.

B.4. Activity

"Activity" refers to a firm's growth. Growth is a key indicator of a financially healthy enterprise. Examples of "Activity" include:

- Change in gross sales – The percent change in sales from one year to the next year.

B.5. Profitability

The profitability of the licensee is of primary concern for prospective investors, which is both domestic and international in scope. Profitability is also of concern to the regulator because the licensee must demonstrate:

(a) that it is a profitable business in which owners will want to retain their investment; but

(b) that it is not so excessively profitable for its owners that the customers suffer either from excessive costs of service or the deterioration of service at the customer's expense.

The following are examples of ratios that measure a firm's profitability:

- Return on Equity – the net earnings of the firm as a percentage of outstanding equity. This is a critical factor in virtually every investment decision and must be evaluated on the basis of international standards.
- Return on Assets – the ratio of earnings to the total value of assets.
- Profit Margin – Net profit after taxes divided by sales for a given 12-month period, expressed as a percentage. This is key factor from a potential investor's viewpoint.

B.6. Leverage

"Leverage" refers to the "portion of fixed costs that represents a risk to the firm."[4] A firm will leverage its investment by acquiring debt and using the proceeds for the construction and maintenance of facilities as well as for the expansion of income-producing services. However, the amount of debt should be limited so that payment of interest on debt can be sustained. The "leverage" factor will become important for Mongolian energy companies once they begin to have positive net income. Positive income will build equity in the energy companies. It is important for the ERA to monitor "leverage." The energy firms should maintain a sufficient equity share in their business to guarantee their willingness to keep the licensee in operation for the benefit of its customers. Around the world many so-called "privatizations" have failed because the owners' equity was so low that there was no disincentive for owners to liquidate the business and benefit greatly from selling-off the firm's tangible assets. It is the regulator's obligation to ensure that licensee owners always have a significant financial stake in their crucial and strategic businesses.

The following are examples of ratios used to measure a firm's leverage:

- Equity Ratio – the ratio of the owners' equity to total assets.
- Debt to Equity Ratio – the ratio of outstanding debt to owner's equity.
- Debt Ratio – the ratio of financed debt to total assets.
- Long-term debt Ratio – the ratio of long-term debt (obligations that will not come due during the current year) to total capitalization.

C. Suggested Financial KPIs

Exhibit I-1 listed below is an example of 8 KPI ratios that measure the six financial categories discussed above:

[4] Shim and Siegel, page 276.

Exhibit I-1
Financial Key Performance Indicators

Indicator	Equation	Measurement Rationale
1. Quick Ratio	Current Assets – Inventory/ Current Liabilities	Liquidity
2. Total Owner's Equity to total Assets (%)	Total Owner's Equity/ Total Assets	Leverage
3. Interest coverage Ratio (times)	Earning before interest and taxes/ Interest Expenses	Coverage
4. Return on Equity (%)	Net Profit/ Total Owner's Equity	Profitability
5. Profit Margin (%):	Net Sales – Cost of goods sold/ Net Sales	Profitability
6. Average collection period (day)	Accounts Receivable/ Average daily sales	Common size
7. Average payable period (day)	Payable Accounts / Net credit purchase	Common size
8. Change is gross sales	(Sales current year/sales prior year) -1	Activity

D. Financial KPIs Applied to Mongolian Energy Companies

Exhibit I-2 provides 2005 financial data from the Mongolian energy companies using the recommended eight, new financial KPIs, listed in Table 1. The data provides a good starting point for assessing financial ratios.[5]

Exhibit I-2
Proposed New Financial KPIs - Mongolian Energy Companies

Licensees	UBEDN	EBEDN	DSEDN	BSEREDN	UBPP-2	UBPP-3	UBPP-4	Darhan PP	Erdenet PP	Transco	UBHN	Dar HN	EES
Quick ratio	0.35	0.52	2 88	0.81	0.22	1.11	0 54	1 05	0.73	0.60	0.31	0.79	2 30
Total Owner's Equity to total Assets	-29%	79%	48%	69%	16%	30%	34%	37%	89%	85%	22%	84%	48%
Interest coverage Ratio (times)	1.1	(69.2)	21.2	(149.9)	(1.9)	4.7	1.1	3.2	0.0	2.6	3.5	0.0	(6.7)
Return on Equity (%)	0.3%	-2.3%	0.7%	-1.1%	-2 6%	4.8%	0.1%	1.4%	-1 2%	0.3%	1.0%	3.1%	-4.1%
Profit Margin (%)	18.5%	5.4%	15.1%	20.9%	9.4%	5.9%	6 2%	7 8%	0 5%	18.6%	4.1%	9 3%	-26.2%
Average collection period (day)	28	6	57	38	60	53	67	62	48	1	33	85	13
Change is gross sales	0.15	0.11	0.13	0.08	0 24	0.12	0.17	0 09	0.11	0.10	0.20	0.17	0.23
Average payable period (day)	113	26	27	85	439	80	358	79	95	319	139	208	42

Supporting data for the above financial KPIs is included in Annex B.

The following two charts illustrate that the financial ratios can be used to make comparisons between energy companies.

[5] Annex B provides the detailed financial information used by ERA staff to prepare Table 2.

Exhibit I-3

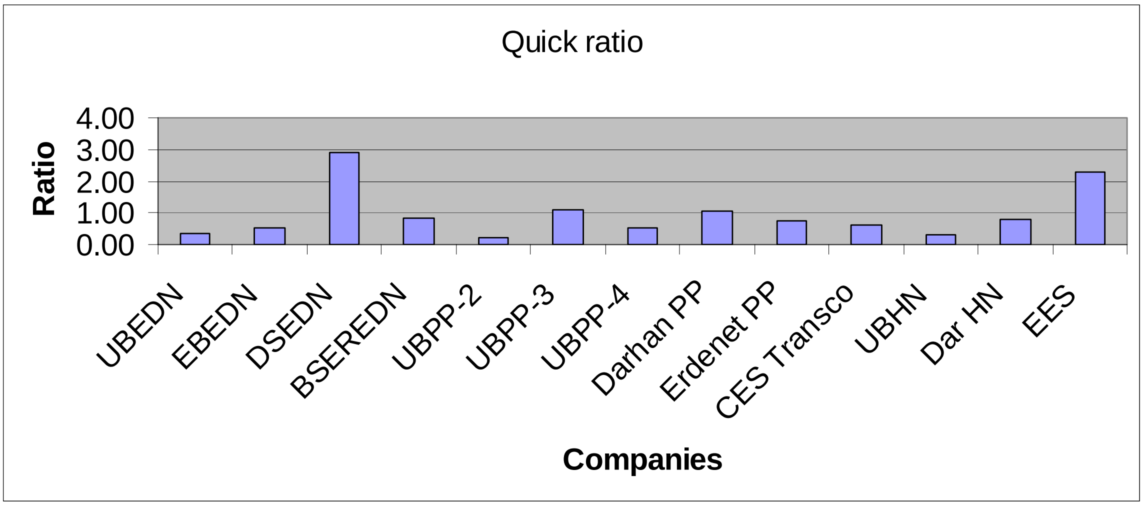
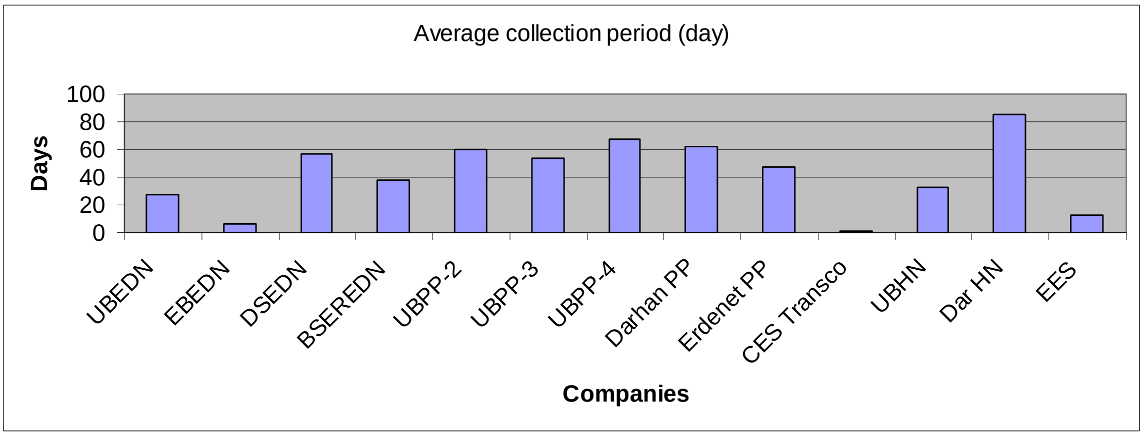


Exhibit I-4



However, the data has some important limitations:

1. The Genco data includes accounts payable over one year. These accounts should be removed. However, ERA staff does not have sufficient information to make this calculation. Including accounts payable that should be "written off" over estimates net income; this distorts: the quick ratio, interest coverage, return on equity, profit margin, and the average payable period.
2. Net credit purchases must include all purchases. Disco data only includes purchases from generators and single buyers. This affects the average payable period ratio.

There may also be additional refinements needed to fully implement International Accounting Standards. The process is incumbent upon the ERA to assure that licensees' financial statements are accurate. Without accurate input information, these financial KPIs have little usefulness.

Initially, financial benchmarks for Mongolian companies should be based upon improvement from recent performance and comparison's between Mongolian energy companies. As energy company performance improves, benchmarks may be based on international norms for comparable companies. Statistics on standard, financial indicators are relatively available world wide.

SECTION II: PERFORMANCE AGREEMENTS

A. Introduction

The ERA has the authority to set energy rates. This can be accomplished by setting energy tariff rates by standard revenue requirement methods, rate of return regulation, or price or revenue caps. In addition, the ERA may regulate the quality of utility performance and services and via other regulatory tools through its authority to set rates and to amend an operator's license.

There are three basic options for regulators to consider for quality regulation:

1. Indirect regulation – Publish information about performance. The ERA currently uses indirect regulation.
2. Minimum Standards – Define boundaries for service quality and provide strong incentives to assure compliance. This option has been popular in EU countries and in California. Often called "guaranteed standards." [6]
3. Incentives Mechanisms -- normally via a performance agreement where the utility is eligible for rewards and penalties based on its performance.

Although this paper will focus on "Incentive Mechanisms" via a performance agreement, the ERA should also consider minimum standards as a regulatory option.

B. Performance Agreement (PA) Definition

A performance agreement is a legal document signed by the regulator and the licensee. The PA is a contract for achieving specified performance targets and specific consequences to the licensee for its performance as measured by selected Key Performance Indicators (KPIs).

Performance agreements have been widely used by US regulators as a means to monitor and provide consequences for areas of concern to regulators. Examples where performance agreements have been utilized include California, Maine, and Massachusetts. Performance standards and agreements have also been used in Romania, Hungry and many European Countries.[7] Performance agreements are under consideration by the Egyptian Regulator (See Annex C). Annex D includes the PA for Southern California Edison and Annex E includes the PA for San Diego Gas & Electric Company.

C. Contents of a PA

The contents of a PA include the following:

1. <u>The Regulator's legal authority to require a licensee to sign a PA.</u>
2. <u>The Key Performance Indicators (KPIs).</u> The agreement includes a detailed description of the KPIs, including definitions, units of measurement, data sources, and the time frame for measuring the reported KPIs.
3. <u>Benchmarks.</u> The PA includes specific information as to target levels.
4. <u>Timeframe.</u> The PA indicates the period to measure performance, for example it may be for one year or multiple years.

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[6] For example, in England, customers are provided financial compensation if the utility does not make a scheduled appointment within a specified hourly time period.

[7] An excellent summary of the European efforts in performance regulation is included in a presentation by Luca Schiavo, "Service Quality Regulation in the Electricity Industry," July 25, 2006; available on the website of the Energy Regulators Regional Association, http://www.erranet.org.

5. Consequences resulting from measured performance.
   a. The PA may include non financial or financial consequences for performance;
   b. Non financial consequences include publication in ERA reports or the press.
   c. Financial consequences to utility companies:
      i. Monetary adjustments to tariff entitlements
      ii. Others

C.1. ERA's Legal Authority to Require Licensees to Have Performance Agreements.

Article 9.1.2 of the Mongolian Energy law provides the ERA with authority "To set operational and licensing terms and requirements for licensees; to monitor compliance with these terms and requirements." In addition the ERA's authority to set tariffs (Article 9.1.3) authorizes the ERA to make a link between the performance agreement and corresponding financial rewards and penalties.

The key steps to establish authority for a PA are:

1. Amend the license to require a performance agreement,
2. Reference the PA to selected revenue requirement components, e.g. the Social Cost component of the licensee's tariff structure.

C.2. Examples of KPIs and financial consequences used in performance agreements

Performance Agreements Implemented by the California Public Utilities Commission:

Southern California Edison[8]

KPIs*:*

- A Customer Satisfaction Measure
- A Reliability Measure, Average Customer Minutes of Interruption (ACMI) & Outage Frequency
- An Employee Health & Safety Measure
- Financial Rewards and Penalties

San Diego Gas and Electric Company[9]

KPIs:

- Occupational Safety and Health Administration (OSHA) Reportable Injury and Illness Index
  - Total Company Work hours
- Electric Reliability Performance Indicators
  - System Average Interruption Duration Index (SAIDI)
  - System Average Interruption Frequency Index (SAIFI)
  - Momentary Average Interruption Frequency Index (MAIFI)
- Financial Rewards and Penalties.

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[8] This performance agreement was first developed in 1997 in compliance with a 1996 commission order. ERA staff have been provided with a detailed compliance filing prepared for this performance agreement, dated August 18, 2003, this document is also included as Annex D.

[9] This performance agreement was first instituted in January 1999. The ERA staff have been provided with the detailed tariff language used by the California commission to implement this agreement. This document is also included as Annex E.

Maine

KPIs:

- New worker safety performance indicator: Ten-year average of each utility's lost work-time accident rate.
- New reliability performance indicators: Ten-year historical average of each utility's SAIDI.
- Distribution line losses (proposed).
- Major outage events excluding storms (proposed).
- Report other reliability-related data (but no penalty):
    - SAIFI & MAIDI.
    - Poorly performing circuits.
    - Capital expenditures for T&D systems.
    - Storm-related major outage event information.

Penalty policies:

- Maximum aggregated penalties — 2% of Distribution company's annual T&D revenues.
- No financial incentives for improving past service quality performance.

Massachusetts

Performance benchmarking rules:

- Performance benchmarked against company historical performance rather than national, regional, or statewide standards.
- Consideration of broader performance standards in future.

KPIs:

- New Service Quality performance indicators for utilities:
    - Telephone calls answered within a specified time.
    - Service appointment met on the same day as requested.
    - On-cycle meter reads.
    - New customer satisfaction performance indicators:
        - Number of complaints received and billing adjustments made by the regulatory agency.
        - Scores on customer satisfaction surveys (but initially only for informational purposes — no revenue penalty).
    - New worker safety performance indicator: Ten-year average of each utility's lost work-time accident rate.
    - New reliability performance indicators:
        - Ten-year historical average of each utility's SAIDI.
        - Distribution line losses (proposed).
        - Major outage events excluding storms (proposed).
    - Report other reliability-related data (but no penalty):
        - SAIFI & MAIDI.
        - Poorly performing circuits.
        - Capital expenditures for T&D systems.
        - Storm-related major outage event information.

Penalty policies:

- Maximum aggregated penalties — 2% of the DISCOs annual T&D revenues.

- No financial incentives for improving past service quality performance.

Egypt (Under consideration by the Egyptian regulator)[10]

KPIs:

- System Average Interruption Frequency Index (SAIFI)
- Residential Complaints per 1000 Residential Customers
- Distribution Equipment Utilization Factor
- Percentage of Technical and Non Technical Losses in Electric Energy
- Quick Ratio
- Average Collection Period
- Interest Coverage Ratio

Consequences**:** variations in license fees since the Egyptian regulator does not have tariff-setting authority..

C.3. KPIs to Consider for a PA in Mongolia

Regulation of quality includes the following broad areas:

- Customer Service, e.g.:
    - Making and keeping appointments,
    - Response to customer enquires,
    - Customer satisfaction surveys
- Continuity of Supply, e.g.:
    - Reliability, e.g. interruption of service
    - Voltage Quality
- Efficiency, e.g.:
    - Technical and financial losses
    - Internal energy uses

The ERA should consider energy losses as one of the KPIs for a PA. The ERA has been closely monitoring energy losses for generation, transmission and distribution. Power station internal usage has been reduced. Likewise, transmission and distribution losses have been reduced.[11] The ERA has established benchmarks for energy losses as part of its current benchmarking system.

The ERA should consider using a KPI measuring power outages for a distribution company PAs. The ERA has been monitoring system outage information using three internationally recognized outage indices: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI). However, the ERA should be confident that licensee reporting information is valid and can be audited.

Preferably, the PA should also use a KPI that measures customer service. However, currently the ERA does not have good data on customer service.

[10] A model performance agreement under consideration by the Egyptian regulator is included in Annex C of this report.

[11] ERA, 2005 Annual Report, indicates that power station internal consumption has been reduced from 22% in 2001 to 18.13 in 2005; transmission and distribution losses of the CES have been reduced from 24 % in 2001 to 19.7% in 2005.

C.4. Example of Financial Consequence:

In Mongolia, energy rates include a “Social Cost” (SC) component in the licensee’s tariffs. SC includes employee allowances for items such as food, transportation, training, supplemental heating allowance, bonuses, and travel. The SC is around 2.5 % of the total revenue requirement. For example, for Power Plant #3 the SC component of the tariff is 1.15 tg/kwhr out of a total tariff of 45.15 tg/kwhr.

The EPRC team and ERA should consider use of the Social Cost component as a means for financial consequences in a performance agreement.

The arguments in favor of using SC include the following:

- Using SC is a part of the rate tariff and thus clearly under ERAs authority,
- SC is financial issue in which all employees have a stake.

If the ERA chooses to use SC in a performance agreement, the ERA should use KPIs that effectively measure:

- aspects of company operations important to customers, and
- operational aspects of company operations that company employees and managers can influence.

D. Performance Agreement Measurements Example

The following is a theoretical example illustrating the calculation of KPIs consequences as part of a Performance Agreement, assuming only two KPIs for the example.

Exhibit II-1
Company A, KPI “I”

KPI	**Energy Losses**	
value range	*Adjustment to Social Cost Tariff*	
%	%	
30.1 or greater	-15	
28.1 to 30.0	-10	
26.1 to 28.0	-5	
23.1 to 26.0	0	"Dead Band"
21.1 to 23.0	5	
19.1 to 21.0	10	
19 or less	15	
2005 Actual	25.3	
2004 Actual	27.2	

Exhibit II-2
Company A, KPI “II”

KPI	SAIFI*	
value range	*Adjustment to Social Cost Tariff*	
#	%	
25.1 or greater	-20	
21.1 to 25	-15	
18.1 to 21	-10	
15.1 to 18	-5	
5.1 to 15	0	"Dead Band"
3.1 to 5	5	
1.1 to 3	15	
1 or less	20	
2005 Actual	13	
2004 Actual	17	

*System Average Interuuption Freguency Index

Exhibit II-3
Summary of Company A's Performance for Period X and Financial Reward/Penalty

KPI	Achieved Value for Period X	% Change in Social Cost Tariff
I (Energy Losses)	28.3%	-5%
II (SAIFI)	1.8	15%
….		
Total		10.0%

D.1. Analysis of Example

The dead band for energy losses was set at between 23.1 % and 26 %, thus performance at the 2005 actual value of 25.3% would not warrant a reward or penalty. However, performance at the 2004 level of 27.2 % would result in a 5% reduction in the social cost tariff. There is a maximum reward of 15 % and a symmetrical maximum penalty of -15%.

The dead band for power outages (SAIFI) is set between 5.1 and 15. In this example, the actual values of 2004 and 2005 would fall between the "dead band," and thus, there would be no reward or penalty. In this example there are four tiers above and below the dead band.

D.2. Options to consider in performance agreement reward formulas:

- The type of financial reward/penalty (e.g. changes in the Social Cost portion of the authorized energy rate tariff)
- The number of KPIs
  - Suggested that the number of KPIs be between 2 and 6.
- The number of tiers in the reward formula (e.g. in the example above KPI #I has three tiers beyond the dead band)[12]
- The size of the tiers (e.g. percentage incentive or penalty)
  - Careful consideration should be made to assure that the reward is not too generous nor the penalty too onerous. For example, the maximum adjustment to the social cost should be 50%.
- Reward/Penalties symmetrical or asymmetrical (rewards/penalties are symmetrical in the examples)

[12] For example, in the Southern California Edison performance agreement, there were 18 tiers in the reliability KPI, 9 tiers in the employee safety KPI and 5 tiers in the customer satisfaction KPI.

  - Symmetrical reward/penalties are fairest to consumers and licensees. They will be more acceptable to licensees than a system that offers little chance of reward or high probability of penalties.
- The size of the "dead band"
  - Often the dead band is set to a wide level, so that normal performance would fall within the dead band, and hence no financial reward or penalty. Performance outside of the dead band would be exceptional, thus deserving financial rewards or penalties.
  - Another school of thought is that the "dead band" should be narrow, thus providing financial consequences for performance.

<u>Recommendation</u>: Set a wide dead band or minimal consequences for the initial performance agreement. This will enable the ERA and licensees to gain experience with PAs and financial consequences, without imposing significant gains or losses.

E. Other Considerations When Implementing Performance Agreements

E.1. Options for Setting Benchmarks

- **External Benchmarks** (Company performance vs. international standards)
  - Subject to data availability and comparability issues
  - Fairness to compare developing companies with companies from fully developed countries
  - Data comparability issues, are all companies using the same method to collect data?
  - Unique circumstances e.g. combined heat generation units are not comparable to other coal plants
- **Internal Benchmarks Company performance vs. other Mongolian companies**
  - Comparability/Fairness issues, e.g. "our company is different"
  - Inconsistencies in data collection
- **Time series** (Company performance vs. previous performance)
  - Difficult to determine where to begin (is the current year "normal," is the performance year "normal?)
- **Negotiated** Benchmarks are negotiated between regulator and company
  - Allow parties to look at external, internal, and time series information to determine benchmarks
  - Obtain acceptance from companies
  - Undue influence from companies may result in easily achievable benchmarks
- **Eclectic** Any reasonable combination of above.
  - Time series or internal benchmark information for base line benchmarks
  - International values used to set "stretch" goals

Initially, the ERA should use a combination of internal, time series and negotiated benchmarks for performance agreements. As Mongolian energy companies improve their performance, external benchmarks should be considered.

E.2. Need for Accurate Reporting

The ERA should be assured that the KPI information used in PA's is accurate. It is conceivable that licensees would distort information in order to receive a favorable result. Random audits of KPI information will put licensee on notice.

In addition, the ERA should consider further measures to assure that licensees are reporting accurate information. The ERA may wish to amend licenses to include a requirement that licensees “never mislead the ERA by an artifice or false statement of fact or law.” For example the California Public Utilities Commission has over 88 rules of practice and procedure. Its first rule, deals with ethics:

> *Any person who signs a pleading or brief, enters an appearance at a hearing, or transacts business with the Commission, by such act represents that he or she is authorized to do so and agrees to comply with the laws of this State; to maintain the respect due to the Commission, members of the Commission and its Administrative Law Judges; and never to mislead the Commission or its staff by an artifice or false statement of fact or law.* [13]

The ERA should consider consequences of violation of its orders, e.g. providing misleading information. This may likewise be accomplished through the ERA’s broad authority under Article 9.1.1 “To issue, amend, suspend and revoke licensees in accordance with this law.”

In addition, the PA may also include provisions for inaccurate information. For example, the PA may indicate that KPI data will be randomly audited and if the ERA finds that the licensee has misled the ERA or reported inaccurate information that it will be ineligible for any reward. In addition, the licensee would be subject to a penalty. The penalty could be based on the PA. For example a maximum penalty could be imposed equal to the outcome had the licensee recorded the poorest level of performance for each KPI in the PA.

E.3. Negotiated Performance Agreement

The ERA should negotiate the terms of the Performance Agreement with each licensee. Negotiation is a different approach for regulators. Regulators are accustomed to issuing orders and looking to the licensee to comply with orders. However, the negotiation process provides an opportunity to develop a performance agreement that uniquely suits the licensee.

Licensees are more likely to accept the notion of performance agreements if they have input. A negotiation process allows each side to openly discuss various KPIs, licensee improvements, etc. However, the ERA should be cautious in its negotiations. Licensees may unduly influence the selection of KPIs and benchmarks to suit their interests resulting in easily obtainable goals and rewards.

The ERA may wish to consider concerns as to its constituency in deciding which KPIs and rewards and penalties to consider.

E.4. Selection of Licensee for the First Performance Agreement

The ERA should think strategically in identifying the first licensee to have a performance agreement. For example choose a licensee that has:

- Better than average performance,
- Progressive management,
- A good working relationship with the ERA.

[13] California Public Utilities Commission Rules of Practice and Procedure, Rule number 1, www.cpuc.ca.gov.

ANNEX A: EXAMPLES OF ERA RANKING OF LARGE AND SMALL ENERGY COMPANIES

ANNEX A: EXAMPLES OF ERA RANKING OF LARGE AND SMALL ENERGY COMPANIES

English translation of press clippings

Daily News (No. 119 (2253) 2006.05.11)

The energy regulatory authority reports

The ERA evaluates performance of energy sector licensees using the main indices on a quarterly basis. The ERA has established the ratings for energy entities based on their performance of the 1st quarter of 2006 using net income, accounts payable and short term liabilities, self use, power transmission and distribution losses, heat network water losses, revenues and expenditures, and reliability of services being rendered as indices for performance measurement. The licensee which has obtained the highest rank is the Ulaanbaatar Power Plant no. 3. The lowest rank is given to the Dalanzadgad Power Plant.

The Ratings for the Energy Entities for the 1st Quarter of 2006

Rating	Licensees
1	Ulaanbaatar Power Plant no. 3
2	Darkhan-Selenge Electricity Distribution Network
3	Darkhan Heat Network
4	Ulaanbaatar Power Plant no. 2
5	Ulaanbaatar Power Plant no. 4
6	Baganur & South Eastern Region Electricity Distribution Network
7	Ulaanbaatar Electricity Distribution Network
8	Western Energy System
9	Eastern Energy System
10	Nalaih Heat Plant
11	Erdenet Power Plant
12	Baganur Heat Plant
13	Ulaanbaatar Heat Network
14	Darkhan Power Plant
15	Central Region Electricity Transmission Network
16	Erdenet Bulgan Electricity Distribution Network
17	Dalanzadgad Power Plant

Daily News (No. 138 (2273) 2006.05.29)

THE ENERGY REGULATORY AUTHORITY REPORTS

The ERA evaluates performance of energy sector licensees using the main indices on a quarterly basis and publishes the quarterly ratings for 17 large energy entities which were created during the sector reform.

Commencing from this year the ERA has started to establish the ratings for other energy entities. The ratings of electricity networks operating in local areas as shown below was established based on indices such as using net income, accounts payable and short term liabilities, distribution losses, reliability of services being rendered and supply interruptions. The licensee which has obtained the highest rank is the Hovsgol –Energy distribution network. The lowest rank is given to the Ulaangom distribution network.

The Rating of the Energy Entities for the 1st Quarter of 2006

Rating	Licensees
1	Hovsgol –Energy Distribution Network
2	Erchim-Suljee Distribution Network
3	Ulaanbaatar Railway
4	Bayan-Olgii Distribution Network
5	Bayanhongor –Energy Distribution Network
6	Hovd Distribution Network
7	EHTE
8	Ulaangom Distribution Network

ANNEX B: PROPOSED NEW FINANCIAL KPIs–MONGOLIAN ENERGY COMPANIES, 2005

ANNEX B: PROPOSED NEW FINANCIAL KPIs–MONGOLIAN ENERGY COMPANIES, 2005

Licensees	UBEDN	EBEDN	DSEDN	BSEREDN	UBPP-2	UBPP-3	UBPP-4	Darhan PP	Erdenet PP	Transco	UBHN	Dar HN	EES
Quick ratio	0.35	0 52	2.88	0.81	0.22	1.11	0.54	1.05	0.73	0 60	0.31	0.79	2.30
Total Owner's Equity to total Assets	-29%	79%	48%	69%	16%	30%	34%	37%	89%	85%	22%	84%	48%
Interest coverage Ratio (times)	1.1	(69.2)	21.2	(149.9)	(1 9)	4.7	1.1	3.2	0.0	2.6	3.5	0 0	(6.7)
Return on Equity (%)	0.3%	-2 3%	0.7%	-1.1%	-2.6%	4.8%	0.1%	1.4%	-1.2%	0 3%	1.0%	3.1%	-4.1%
Profit Margin (%)	18.5%	5.4%	15.1%	20.9%	9.4%	5.9%	6.2%	7.8%	0.5%	18 6%	4.1%	9.3%	-26.2%
Average collection period (day)	28	6	57	38	60	53	67	62	48	1	33	85	13
Change is gross sales	0.15	0.11	0.13	0.08	0.24	0.12	0.17	0.09	0.11	0.10	0 20	0.17	0.23
Average payable period (day)	113	26	27	85	439	80	358	79	95	319	139	208	42

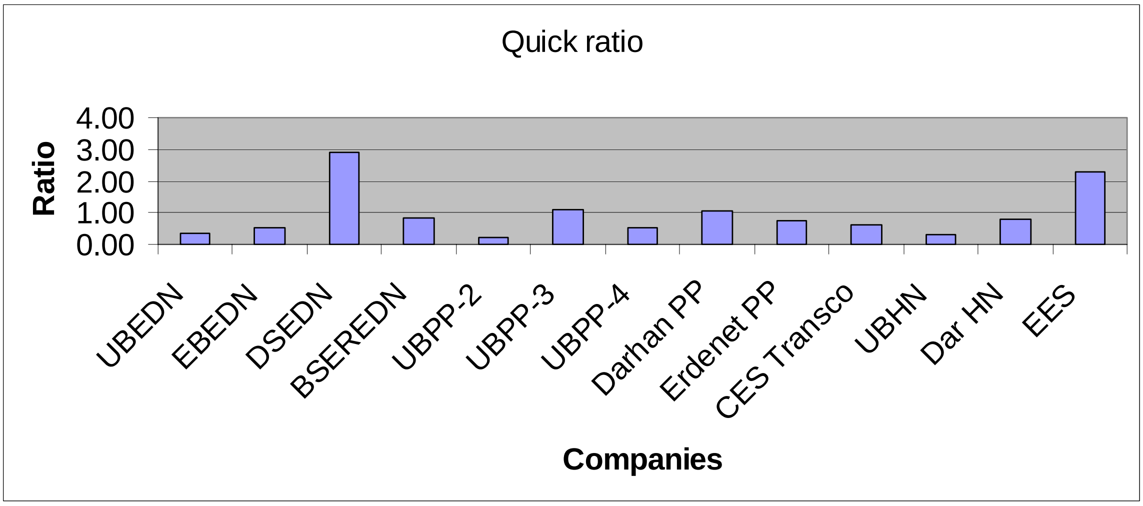
Note:

1. Accounts Receivables of gencos excludes receivables of pervious years
2. Accounts Payable of gencos may include arrears aged more than 1 year due to difficulties in separating them
3. Accounts Receivable and Payable of discos exclude previous years receivables and payables
4. Net credit purchases are power and heat purchases only.
5. Interest expenses are based on the sub-loan agreements.

Financial Details Supporting Financial Rations
2005
(000)Tg.

Ratios	UBEDN	EBEDN	DSEDN	BSEREDN	UBPP-2	UBPP-3	UBPP-4	Darhan PP	Erdenet PP	Transco	UBHN	Dar HN	EES
Current Ratio													
Current Assets	11,318.5	2,232.6	3,243.8	1,750.3	1,251.8	10,045.0	20,736.8	3,044.8	2,090 2	1,240.1	2,275.0	751.9	1,736.8
Current Liabilities	10,059.6	2,872.8	994.9	1,326 3	3,466.6	3,910 8	22,180.1	1,427.2	1,332.2	628.2	6,284.5	706.5	179.9
Current Ratio	1.13	0.78	3.26	1.32	0 36	2.57	0.93	2.13	1.57	1 97	0.36	1.06	9.65
Accounts Receivable	3,006.0	767.5	2,445 8	755.0	662.2	3,794.2	10,972.1	1,490.9	939.4	19.4	1,884.2	545.8	252.4
Share in Current Assets, %	27%	34%	75%	43%	53%	38%	53%	49%	45%	2%	83%	73%	15%
Quick Ratio													
Cash	553.3	715.9	419.2	325 2	97.3	557 2	985.3	12.4	26.9	355.3	90.5	14.6	161.1
Short term investment													
Accounts Receivable	3,006.0	767.5	2,445.8	755 0	662.2	3,794.2	10,972.1	1,490.9	939.4	19.4	1,884.2	545.8	252.4
Current liabilities	10,059.6	2,872.8	994.9	1,326 3	3,466.6	3,910 8	22,180.1	1,427.2	1,332.2	628.2	6,284.5	706.5	179.9
Quick ratio	0.35	0.52	2.88	0.81	0 22	1.11	0.54	1.05	0.73	0.60	0.31	0.79	2.30
Total Owners' Equity to Total Assets													
Equity	(7,886.8)	10,488.2	4,225.0	7,337 2	887.8	28,835.3	60,309.8	5,415.1	10,718 8	32,548.0	16,021.5	3,661.7	11,217.1
Total Assets	27,295.8	13,324.6	8,847.6	10,676 0	5,424.2	96,425.7	179,454.9	14,456.6	12,054.3	38,416.5	74,509.0	4,368.2	23,251.4
Total Owner's Equity to total Assets (%)	-29%	79%	48%	69%	16%	30%	34%	37%	89%	85%	22%	84%	48%
Interest Coverage Ratio													
EBIT	1,223.1	(297.6)	61.6	(119.9)	(91.0)	5,835.7	2,435.4	289.3	(141.5)	412.0	1,241.8	135.3	(963.3)
Interest expense (short & long term)	1,135.7	4.3	2.9	0 8	48.0	1,239.2	2,260.4	90.8		157.2	358.9		143.4
Interest coverage Ra io (times)	1.1	(69.2)	21.2	(149 9)	(1.9)	4.7	1.1	3.2		2.6	3.5		(6.7)
Return on Equity													
Net Profit	87.4	(301.9)	58.7	(120.7)	(139.0)	4,596 5	175.0	198.5	(141.5)	99.4	771.4	135.3	(963.3)
Equity	27,295.8	13,324.6	8,847.6	10,676 0	5,424.2	96,425.7	179,454.9	14,456.6	12,054.3	38,416.5	74,509.0	4,368.2	23,251.4
Return on Equity (%)	0.3%	-2.3%	0.7%	-1.1%	-2.6%	4.8%	0.1%	1.4%	-1.2%	0.3%	1.0%	3.1%	-4.1%
Profit Margin													
Net Sales 2005/01/01-12/31	39,697.5	43,131.4	15,702.7	7,275.7	4,000.3	25,988.4	59,622.8	8,811.5	7,196 8	4,951.4	20,747.1	2,338.5	2,892.7
CGS 2005/12/31	32,353.1	40,805.6	13,329.5	5,755 5	3,625.0	24,457.1	55,921.5	8,125.8	7,162.1	4,029.3	19,894.4	2,122.1	3,650.9
Profit Margin (%)	18.5%	5.4%	15.1%	20.9%	9.4%	5.9%	6.2%	7.8%	0.5%	18.6%	4.1%	9.3%	-26.2%
Average Collection Period													
Accounts Receivable - 2005/12/31	3,006.0	767.5	2,445.8	755.0	662.2	3,794.2	10,972.1	1,490.9	939.4	19.4	1,884.2	545.8	252.4
Net Sales 2005/01/01-12/31	39,697.5	43,131.4	15,702.7	7,275.7	4,000.3	25,988.4	59,622.8	8,811.5	7,196 8	4,951.4	20,747.1	2,338.5	7,196.8
Average collection period (day)	28	6	57	38	60	53	67	62	48	1	33	85	13
Change in Gross Sales													
Net Sales 2005/12/31	39,697.5	43,131.4	15,702.7	7,275.7	4,000.3	25,988.4	59,622.8	8,811.5	7,196.8	4,951.4	20,747.1	2,338.5	2,892.7
Net Sales 2004/12/31	34,561.3	38,948.6	13,859.8	6,751 0	3,236.1	23,263.7	50,911.0	8,119.4	6,509.8	4,492.4	17,228.2	2,007.2	2,360.4
Change is gross sales	0.15	0.11	0.13	0.08	0.24	0.12	0.17	0.09	0.11	0.10	0.20	0.17	0.23
Average Payable Period													
Accounts Paybale 2005/12/31	10,059.6	2,872.8	994.9	1,326 3	3,466.6	3,910.8	22,180.1	1,427.2	1,332 2	628.2	6,284.5	706.5	179.9
Net Credit Purchase	32,557.2	40,807.8	13,622.2	5,711 3	2,884.8	17,807.3	22,629.9	6,552.6	5,121.3	717.9	16,448.5	1,241.9	1,550.7
Average payable period (day)	113	26	27	85	439	80	358	79	95	319	139	208	42

Note:
1. Accounts Receivables of gencos excludes receivables of pervious years
2. Accounts Payable of gencos may include arrears aged more than 1 year due to difficulties in separating them
3. Accounts Receivable and Payable of discos exclude previous years receivables and payables
4. Net credit purchases are power and heat purchases only.
5. Interest expenses are based on the sub-loan agreements.


Quick ratio
Ratio
4.00
3.00
2.00
1.00
0.00
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EBEDN
DSEDN
BSEREDN
UBPP-2
UBPP-3
UBPP-4
Darhan PP
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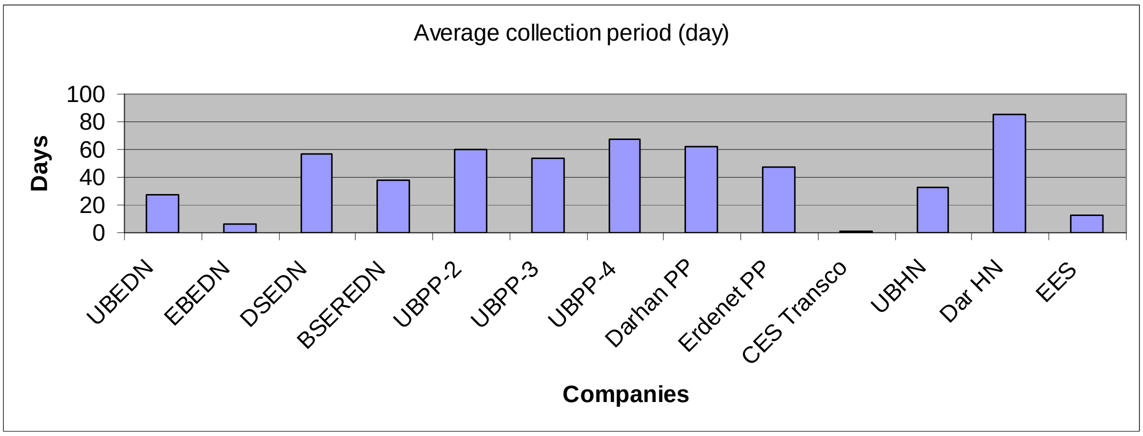
Average collection period (day)
Days
100
80
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UBEDN
EBEDN
DSEDN
BSEREDN
UBPP-2
UBPP-3
UBPP-4
Darhan PP
Erdenet PP
CES Transco
UBHN
Dar HN
EES
Companies

ANNEX C: EXAMPLE OF A PERFORMANCE AGREEMENT - EGYPT

ANNEX C: EXAMPLE OF A PERFORMANCE AGREEMENT - EGYPT[14]

Dated as of [INSERT DATE] 2005

THE ELECTRIC UTILITY AND CONSUMER PROTECTION REGULATORY AGENCY

– AND –

THE ALEXANDRIA DISTRIBUTION COMPANY

PERFORMANCE AGREEMENT

MADE IN CAIRO,

ARAB REPUBLIC OF EGYPT

PERFORMANCE AGREEMENT

THIS PERFORMANCE AGREEMENT (this “Agreement”) is made on the [INSERT] the Day of [INSERT DATE], by

THE ELECTRIC UTILITY AND CONSUMER PROTECTION REGULATORY AGENCY (“THE AGENCY”), a legal entity established under the Presidential decree Number 339 for the year 2000, with its head office at [INSERT ADDRESS OF AGENCY;

and

ALEXANDRIA DISTRIBUTION COMPANY (“the Licensee”), a [limited liability] company incorporated under the laws of the Arab Republic of Egypt (“the Licensee”), with its head office at [INSERT LOCATION], [Egypt]. Each of the Agency and the Licensee are herein referred to individually as “Party” and, collectively, as the “Parties”.

RECITALS

WHEREAS, Presidential decree Number 339 (“the Decree”) obligates the Agency to ensure the quality of the technical and administrative services provided by the Licensee to consumers;

WHEREAS, pursuant to its authority under the Decree the Agency has granted a License (“License”) to the Licensee to provide electricity services in the Arab Republic of Egypt;

WHEREAS, pursuant to the License the Licensee is obligated to make periodic reports to the Agency that fairly and accurately reflect the Licensee’s performance;

---

[14] This performance agreement example was prepared under a USAID contract in support to the Egyptian energy regulator. It was provided to the Egyptian regulator for consideration in developing and negotiating performance agreements.

WHEREAS, the Agency has elected to formalize the performance criteria required under the License in this Agreement, and pursuant to its terms, to measure and reward the Licensee's improved performance;

NOW THEREFORE the Parties hereby agree that the mutual rights and obligations of each on the matter of Licensee rewards in consideration for improved performance shall be as set forth in this Agreement; and

SPECIFICALLY, pursuant to the terms of the Decree, the License and this Agreement;

(a) the Licensee shall provide the Agency the information it requires to fairly evaluate the Licensee's financial and technical performance;

(b) the Licensee, by a senior officer thereof, shall certify to the Agency the source and accuracy of all information it provides to the Agency with respect to its financial and technical performance evaluation of the Licensee;

(c) the Agency shall establish and publish a schedule of Licensee Rating Criteria including minimum standards for financial and technical performance;

(d) the Agency shall measure the Licensee's financial and technical performance according to the Licensee Rating Criteria;

(e) the Agency shall deliver its findings as to the Licensee's financial and technical performance; and

(f) the Agency shall grant benefits and rewards to the Licensee for financial and technical performance that meet or exceed its minimum standards.

AGREEMENT

1. The Agency, relying solely upon audited information provided to it by the Licensee in accordance with the terms of its License, shall review the Key Performance Indicators set out in Schedule A.
2. The Agency shall rate the Licensee according to the rating tables set out in Schedule B.
3. Based upon the assignment of ratings by the Agency to the Licensee as set forth in Schedules A and B, the Licensee shall be entitled to a discount or additional charge in its licensee fee as set out in Schedule C.
4. The period of performance for the rating shall begin on July 1, 2005 and conclude 12 months later on June 30, 2006.
5. The discount or penalty calculated in Schedule C, shall be assessed on the licensee's forthcoming annual regulatory fee for the period [INSERT DATE]

IN WITNESS WHEREOF, the Parties have executed and delivered this Agreement under seal as of the date first above written.

THE AGENCY	THE ALEXANDRIA DISTRIBUTION COMPANY
By: Mohammed El Sobki	By: ……………………….
Title: Director	Title: ……………………...

SCHEDULE A

Key Performance Indicators

1. System Average Interruption Frequency Index (SAIFI)

This KPI indicates the average number of interruptions experienced by a customer each year. The value is expressed as a number of interruptions in a year.

2. Residential Complaints per 1000 Residential Customers

This KPI indicates the total number of complaints per each block of 1000 residential customers. It is expressed as a number per year.

3. Distribution Equipment Utilization Factor

This KPI measures annual sales within the network divided by the distribution network capability. The value is expressed in percent.

4. Percentage of Technical and Non Technical Losses in Electric Energy

This KPI indicates the technical and financial losses on the distribution system. The value is expressed in percent.

5. Quick Ratio

This KPI measures the company's ability to meet its current liabilities with its most liquid asses. It is the ratio of current assets to current liabilities.

6. Average Collection Period

This KPI is calculated by dividing receivable accounts times 365 by the net credit sales. The value is expressed in number of days.

7. Interest Coverage Ratio

This KPI is calculated by dividing earnings before interest expense and taxes by interest expense. The value is expressed as a ratio, which can be positive or negative.

SCHEDULE B

Licensee Rating Tables

Upon evaluation of the information provided to the Agency by the Licensee, the Agency shall assign a rating to the Licensee as follows:

Table 1
SAIFI

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
over 25	7.14
21.1 to 25	4.76
15.1 to 20	2.38
9.1 to 14	**0**
5.1 to 9	-2.38
2.1 to 5	-4.76
2.0 or less	-7.14

Table 2
Residential Complaints per 1000 Residential Customers

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
8.1 or less	7.14
7.1 to 8	4.76
6.1 to 7	2.38
4.1 to 6	**0**
3.1 to 4	-2.38
2.1 to 3	-4.76
2.0 or less	-7.14

Table 3
Distribution Equipment Utilization Factor

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
under 16.00	7.14
16.00 to 16.9	4.76
17.00 to 17.9	2.38
18.00 to 18.5	0
18.6 to 19.5	-2.38
19.6 to 20.5	-4.76
over 20.5	-7.14

Table 4
Percentage of Technical and Financial Losses

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
over 15.0	7.14
13.1 to 15.0	4.76
11.1 to 13.0	2.38
10.1 to 11.0	**0**
9.5 to 10.0	-2.38
9.0 to 9.4	-4.76
less than 9.4	-7.14

Table 5
Quick Ratio

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
.6 or less	7.14
.69 to .6	4.76
.74 to .70	2.38
.75 to .78	**0**
.79 to .85	-2.38
.86 to .99	-4.76
1.0 or greater	-7.14
.6 or less	7.14

Table 6
Average Collection Period

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
over 195	7.14
185.1 to 195	4.76
170.1 to 185	2.38
160.1 to 170	**0**
130.1 to 160	-2.38
110.1 to 130	-4.76
over 195	7.14

Table 7
Interest coverage ratio

Measured value of KPI for rating period	Percent discount (-) or premium (+) on the license fee for the forthcoming period
less than 0	7.14
0 to .49	4.76
.5 to .89	2.38
.90 to 1.1	**0**
1.0 to 1.5	-2.38
1.51 to 1.99	-4.76
2.0 or better	-7.14

SCHEDULE C

Summary of Rewards and Penalties

Key Performance Indicator	Licensee Achieved Value for Rating Period	Percent discount (-) Or Penalty (+) on License Fee.
1. SAIFI		
2. Residential complaints		
3. Dist. Equipment Util. Factor		
4. Financial & Tech. Losses		
5. Quick Ratio		
6. Average Collection Period		
7. Interest Coverage Ratio		
Total Penalty (+)/Discount (-)	-	

ANNEX D: EXAMPLE OF A PERFORMANCE AGREEMENT – SOUTHERN CALIFORNIA EDISON PERFORMANCE AGREEMENT

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Akbar Jazayeri
Director of Revenue and Tariffs

August 18, 2003

ADVICE 1608-E-B
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Supplement to the Performance Based Ratemaking (PBR) Performance Report for 2001

In compliance with Decision (D.) 96-09-092, Southern California Edison Company (SCE) submits for filing its Distribution Performance Based Ratemaking (PBR) Mechanism 2001 Performance Report (Report). Advice 1608-E-B replaces Advice 1608-E-A in its entirety. The revised report excludes recorded expenses related to SCE's participation in the Federal Energy Regulatory Commission's (FERC) investigation of the trading practices of wholesale energy marketers during the California Energy crisis. As a result of this FERC proceeding, SCE has received one refund payment from energy trader Reliant Energy Services. Pursuant to SCE's Settlement Agreement with the California Public Utilities Commission (Commission),[1] SCE may recover expenses incurred by SCE in its attempt to get refunds for its customers from any refunds actually received as the result of FERC's investigation. Therefore, SCE is excluding all such expenses from its PBR Report, since these expenses will be recovered through "gross" refunds. The report also corrects a minor error in the calculation of synchronized interest.

PURPOSE

This filing submits SCE's Report for 2001 as set forth in Preliminary Statement, Part CC, PBR Distribution Rate Performance Mechanism (PDRPM). As a result of the Commission's conversion of SCE's PBR to a revenue index in D.02-04-055 effective June 14, 2001, SCE has included the amount recorded

[1] On October 5, 2001, the United States District Court approved the Settlement Agreement.

P.O. Box 800 2244 Walnut Grove Ave. Rosemead, California 91770 (626) 302-3630 Fax (626) 302-4829

in the Electric Distribution Revenue Adjustment Memorandum Account in the amount of $43.947 million in 2001 PBR distribution revenue.[2]

BACKGROUND

Pursuant to D.96-09-092, and SCE's Preliminary Statements, Part BB, PBR Distribution Rate Adjustment Mechanism, Section 7.b, and Part CC, PDRPM, Section 10, SCE makes an annual filing for each year that the PDRPM is in effect. On May 4, 2001, SCE filed an Expedited Petition for Modification of D.96-09-092 (Petition) requesting, among other things, immediate modification of its PBR mechanism to comply with Assembly Bill (AB) X1-29, signed into law on April 11, 2001. ABX1-29 added Section 739.10 to the Public Utilities (PU) Code, which directed the Commission to ensure that estimates of electrical sales do not result in material over- or under-collection. In April 2002, the Commission issued D.02-04-055 which modified SCE's PBR Mechanism to be consistent with PU Code Section 739.10.

The Job Creation and Worker Assistance Act of 2002 (HR 3090), enacted on March 9, 2002, authorizes additional first-year depreciation for qualifying property and applies retroactively to a portion of 2001. The additional tax depreciation increases deferred tax reserves which in turn reduces rate base. The effects of HR 3090 are incorporated in this filing.

SCE's annual PBR advice letter includes: (1) SCE's request, if any, for recognition of and recovery of Potential Z-Factors; and (2) the details of the operation and the results of SCE's performance under the PDRPM; including the derivation of any shared earnings, earned rewards or assessed penalties resulting from application of the separate performance mechanisms for Net Revenue Sharing, Customer Satisfaction, Average Customer Minutes of Interruption (ACMI), Outage Frequency, and Employee Health and Safety.

2001 PBR PERFORMANCE OVERVIEW

(1) Recovery of Potential Z-Factors

SCE is not seeking recovery of any Potential Z-Factors in this advice filing.

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[2] Pursuant to PU Code Section 739.10 and D.02-04-055, the Commission established a methodology for setting SCE's Distribution PBR revenue requirement for the period from June 14 through December 31, 2001 and ordered SCE to establish a balancing account to ensure that errors in estimates of electricity sales do not result in material over- or under-collections of the revenues authorized by the adopted methodology (D.02-04-055, Conclusion of Law #1, and Ordering Paragraphs 2 and 3). Advice Letters 1619-E and 1619-E-A, implementing D.02-04-055, were approved on June 17, 2002.

(2) PBR Performance

For 2001, SCE's calculation of the PBR Distribution Rate Revenue Sharing Mechanism results in an amount owed to SCE (negative sharing) from its customers of $21.942 million. This negative sharing amount includes an additional $43.947 million of distribution revenue from June 14, 2001 through December 31, 2001 associated with conversion of PBR to a revenue index in accordance with D.02-04-055. In addition, SCE met or exceeded established Service Quality Performance Mechanism standards resulting in rewards totaling $18 million. Table 1 summarizes these results which will be debited to the PBR Distribution Rate Performance Memorandum Account and are discussed in more detail below and in the attached Report.

Table 1
2001 Net Revenue Sharing and (Rewards)/Penalties

	(Millions of dollars)
(A) Customer Share of PBR Revenues	$(21.942)
(B) Customer Satisfaction Measure	(8.000)
(C) Reliability Measure, ACMI	0
Reliability Measure, Outage Frequency	(5.000)
(D) Employee Health & Safety Measure	(5.000)
Total	$(39.942)

(A) PBR Financial Performance[3]

SCE's 2001 financial performance was below the benchmark PBR Distribution Return on Equity (ROE) primarily due to the sales impact of California's aggressive efforts to conserve electricity during the state's electricity crisis.[4] SCE's 2001 financial performance results in a PBR Distribution ROE that is 114 basis points less than the benchmark ROE.[5] Since this result is below the deadband of the net revenue sharing mechanism (more than 50 basis points below the benchmark ROE), net revenue sharing is triggered. For more detailed information, refer to Section III of the Report.

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3 Beginning in April 1998, SCE's nongeneration PBR became a distribution PBR. As filed in Advice 1344-E, revenues and costs associated with ISO-controlled transmission facilities are excluded in calculating the financial performance.

4 Among these programs were the Governor's 20/20 program, a strongly inverted residential rate design with very high tailblock rates, a variety of utility demand-side management programs, the state-sponsored "Flex Your Power" advertising program encouraging the public to conserve, the many conservation programs created and funded by ABX1-29, and new load management programs authorized by the Commission and the Legislature.

5 Includes $43.947 million of additional revenue, pursuant to D.02-04-055. (See footnote 1, above.)

(B) Customer Satisfaction Measure

The Customer Satisfaction Rating measures overall customer satisfaction with SCE's service. This rating is determined annually based on survey results obtained by an outside consultant. SCE has calculated a reward of $8 million associated with SCE's 2001 Customer Satisfaction measure. For more detailed information on the Customer Satisfaction Measure, refer to Section IV.B of the Report.

(C) Reliability Measures, ACMI & Outage Frequency

The Average Customer Minutes of Interruption (ACMI) measures customer service interruptions in terms of the average minutes of service interruptions per customer, excluding all events which have a duration of more than 5.0 minutes of ACMI in a 24-hour period. Outage Frequency measures the number of circuit interruptions excluding all events which have a duration of more than 5.0 minutes of ACMI in a 24-hour period. These measures are based on two-year rolling averages. The two-year average ACMI index was within the deadband of its mechanism and thus no reward was earned or penalty was assessed. For the two-year Outage Frequency performance, SCE earned a reward of $5 million. For more detailed information on the Reliability Measures, refer to Section IV.D & E of the Report.

(D) Employee Health & Safety Measure

Rewards or penalties for employee safety are determined based on SCE's performance related to the frequency of all industrial injuries and illnesses. SCE has calculated a reward of $5 million associated with SCE's Employee Health and Safety Measure. For more detailed information on the Employee Health & Safety Measure, refer to Section IV.F of the Report.

PBR DISTRIBUTION RATE PERFORMANCE MEMORANDUM ACCOUNT

In accordance with D.96-09-092, D.97-10-057, and Resolution E-3514, SCE established the PBR Distribution Rate Performance Memorandum Account (PDRPMA) to record revenue sharing resulting from the PBR net revenue sharing mechanism and all rewards and penalties resulting from the application of the service quality performance mechanisms.

Thus, for an effective date of January 1, 2002, a debit in the amount of $39.942 million would record to the PDRPMA reflecting net revenue sharing and the service quality performance rewards for 2001. Upon Commission approval of this advice letter, SCE will transfer the Commission-approved balance in the PDRPMA to the PBR Exclusions Distribution Adjustment Mechanism (EDAM) Balancing Account.

COST OF CAPITAL TRIGGER MECHANISM

The Cost of Capital Trigger Mechanism was established to adjust SCE's Authorized ROE for changes in interest rates and to adjust PBR Distribution Rates to account for changes in the Authorized ROE. The Trigger Mechanism uses an index which tracks changes in Aa Utility Bond rates. In a November 1, 2001, letter to Mr. Paul Clanon, Energy Division Director, SCE reported that the Aa Utility Bond rate for the 12-month period ending September 2001 was 7.69 percent. Since this was less than 100 basis points above the current Trigger Value of 7.50 percent, the Trigger Mechanism was not activated. For more detailed information, refer to Section V of the Report.

DISTRIBUTION FACILITY FAILURE RATE DATA

In D.98-08-015, the Commission ordered SCE to gather data on distribution component and cable connection failure rates and to report such information during the term of the existing PBR.

SCE has assembled data relative to equipment failure rates for its major distribution facilities. In compliance with D.98-08-015, SCE is reporting the number of failures for specific utility distribution facilities listed in General Order 165 and cable connections that resulted in circuit interruptions during 2001. For more detailed information, refer to Section VI of the Report.

DATA REPORTING COMMITMENTS ADOPTED IN D.99-12-035

In D.99-12-035, the Commission ordered SCE to report data relative to busy conditions on inbound customer telephone trunk lines, streetlight repairs, service guarantee commitments, and customer erroneous disconnects. SCE has gathered this data and is reporting it in compliance with D.99-12-035. For more detailed information, refer to Section VII of the Report.

This advice filing will not increase any rate or charge, cause the withdrawal of service, or conflict with any other schedule or rule.

EFFECTIVE DATE

This advice letter will become effective upon Commission approval.

NOTICE

Anyone wishing to protest this advice letter may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received by the Energy Division and SCE no later than 20 days after the date of this advice filing. Protests should be mailed to:

IMC Program Manager
c/o Jerry Royer
Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4002
San Francisco, California 94102
Facsimile: (415) 703-2200
E-mail: jjr@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Akbar Jazayeri
Director of Revenue and Tariffs
Southern California Edison Company
2244 Walnut Grove Avenue, Rm. 303
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Bruce Foster
Vice President of Regulatory Operations
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2040
San Francisco, California 94102
Facsimile: (415) 673-1116
E-mail: Karyn.Gansecki@sce.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section III, Paragraph G, of General Order No. 96-A, SCE is mailing copies of this advice filing to the interested parties shown on the attached service list. Address change requests to the attached GO 96-A Service List should be directed to Emelyn Lawler at (626) 302-3985 or by electronic mail at AdviceTariffManager@sce.com. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021, or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing open for public inspection at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at http://www.sce.com/adviceletters.

For questions on the Report, Susan Reed may be reached at (626) 302-1965 or by electronic mail at Susan.Reed@sce.com.

Southern California Edison Company

Akbar Jazayeri

AJ:sr
Enclosures

SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

SCE'S DISTRIBUTION PERFORMANCE BASED

RATEMAKING (PBR) MECHANISM

<u>REVISED</u>

2001 PERFORMANCE REPORT

Before the
Public Utilities Commission
of the
State of California

August 18, 2003

SCE'S DISTRIBUTION PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

2001 PERFORMANCE REPORT

(January 1, 2001 through December 31, 2001)

Table of Contents

I. Introduction

2001 was the fifth year of operation for Southern California Edison's (SCE or Company) Distribution Performance Based Ratemaking (PBR) mechanism.[1] The purpose of this report is to summarize SCE's 2001 Distribution PBR performance.

This report is filed pursuant to California Public Utilities Commission Decision No. 96-09-092 (D.96-09-092) and SCE's Preliminary Statements Parts BB, CC, and XX. This filing includes financial data from SCE's distribution operations and details of the operation of SCE's current PBR Distribution Revenue Requirement Performance Mechanism (PDRRPM).

The purpose of the PDRRPM is to implement the net revenue sharing mechanism for PBR distribution rate revenues and to provide for rewards and penalties based on SCE's recorded performance measured against established criteria in the following four categories: (1) Customer Satisfaction, (2) Outage Duration, or Average Customer Minutes of Interruption (ACMI), (3) Outage Frequency, and (4) Employee Health and Safety.

The report is a revised report submitted in compliance with Commission Decision No. 02-04-055 (D.02-04-055) in response to SCE's petition to modify its Distribution PBR mechanism (Petition in A.93-12-029).[2] Based on D.02-04-055, SCE submitted Advice Letters 1619-E and 1619-E-A that set forth Preliminary Statement Part XX and calculated a revenue requirement for the period from June 14, 2001 through December 31, 2001 in accordance with the Commission's methodology. As a result, SCE has recorded $43.947 million in Electric Distribution Revenue Adjustment Balancing Account (EDRABA) revenue for 2002 that is included with recorded 2001 PBR revenue.[3] SCE's 2001 recorded PBR Distribution Return On Equity (ROE) is 114 basis points less than the

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[1] SCE, in Advice Letter 1344-E, revised references in its Preliminary Statements to change the title of the PBR mechanism from Nongeneration PBR to Distribution PBR. This change reflects that on April 1, 1998, the Federal Energy Regulatory Commission assumed jurisdiction over the portion of SCE's transmission system subject to operational control by the California Independent System Operator (ISO).

[2] On May 4, 2001, SCE filed a petition to modify D.96-09-092 (Southern California Edison Company's Expedited Petition for Modification of D.96-09-092). In its petition, SCE requested, among other things, an immediate modification of its PBR mechanism to comply with the new requirements of ABX1-29, signed into law on April 11, 2001. ABX1-29 added Section 739.10 to the Public Utilities Code.

[3] Pursuant to Public Utilities Code Section 739.10 and D.02-04-055, the Commission established a methodology for setting SCE's Distribution PBR revenue requirement for the period from June 14 through December 31, 2001 and ordered SCE to establish a balancing account to ensure that errors in estimates of electricity sales do not result in material over- or under-collections of the revenues authorized by the adopted methodology (D.02-04-055, Conclusion of Law #1, and Ordering paragraphs #2 and #3). Advice letters 1619-E and 1619-E-A, implementing D.02-04-055, were approved on June 17, 2002.

benchmark ROE. Since this result is below the deadband of the net revenue sharing mechanism (more than 50 basis points below the benchmark ROE), net revenue sharing is triggered, yielding a customer share of PBR net revenues equal to $(21.942) million. SCE will thus recover $21.942 million from customers through the PBR Distribution Revenue Requirement Performance Memorandum Account (PDRRPMA). The details of the net revenue sharing mechanism are provided in Section III.C, Quantification of Net Revenue Sharing Mechanism Results. The treatment of balances in the PDRRPMA is described in SCE's Preliminary Statement, Part N.26.

SCE’s 2001 Customer Satisfaction performance resulted in a reward of $8 million. SCE’s Outage Duration performance was within the deadband range of the mechanism and, thus, SCE neither earned a reward nor was assessed a penalty. SCE’s Outage Frequency performance yielded a reward of $5 million. SCE’s Employee Health and Safety performance resulted in the maximum reward of $5 million.

Table I.1 summarizes the results of $21.942 million of net revenue sharing and the service quality rewards of $18 million. These amounts will be recovered through the PDRRPMA of SCE’s Preliminary Statement, Part N, in accordance with D.96-09-092, D.97-10-057, D.02-04-055, and Resolution E-3514.

Table I.1

Sum of Net Revenue Sharing and (Rewards)/Penalties	
	(Millions of dollars)
Customer Share of PBR Net Revenues	$(21.942)
Customer Satisfaction Measure	$ (8)
Reliability Measure, ACMI	$ 0
Reliability Measure, Frequency	$ (5)
Employee Health and Safety Measure	$ (5)
Total	$(39.942)

SCE also includes in this report the following information as ordered by the Commission: (1) the composition of the Cost of Capital Trigger Mechanism's bond index; (2) distribution facility failure rate data; and (3) other data as required by D.99-12-035 (SCE's Distribution PBR midterm review decision). In D.96-09-092, the Commission directed SCE to implement a Cost of Capital Trigger Mechanism and to track the monthly composition of the bonds that comprise the mechanism's index. This information is provided in Section V of this report. In D.98-08-015 (the "PBR Service Reliability Decision"), the Commission directed SCE to report the frequency of circuit interruptions resulting from the failure of the types of equipment listed in General Order 165 and cable connections. Section VI of this report provides this information. In D.99-12-035, the Commission directed SCE to report data relative to busy conditions on inbound customer telephone trunk lines, streetlight repairs, service guarantee commitments, and customer service erroneous disconnects. This information is provided in Section VII of this report.

II. PBR Distribution Rate Adjustment Mechanism

The PBR Distribution Rate Adjustment Mechanism (PDRAM) contains an Update Rule that provides for an annual adjustment to PBR Distribution Rate levels.[4] This adjustment, calculated as the PBR Distribution Rate Adjustment Factor (PDRAF), is derived from the forecast Consumer Price Index (CPI) and modified by a productivity pledge (expressed as X). After the first year of operation, a correction factor is applied to reflect the difference between the forecast and recorded escalation in the previous year. The PDRAF is reported annually in November of each year that the PBR is in effect through an advice letter to the Commission. Table II.1 summarizes these factors and adjustments.

Table II.1

PBR Distribution Rates Update

	CPI	X	Correction Factor	Update Rule
1997[5]	3.03%	1.2%	---	1.0183
1998[6]	2.43%	1.4%	0.9925	1.0027
1999[7]	2.70%	1.6%	0.9926	1.0035
2000[8]	2.67%	1.6%	0.9936	1.0042
2001[9]	1.94%	1.6%	1.0101	1.0135

[4] Effective with the approval of Advice Letters 1619-E and 1619-E-A, the PBR Distribution Rate Adjustment Mechanism (PDRAM) is now termed the PBR Distribution Revenue Requirement Adjustment Factor (PDRRAF). See SCE's Preliminary Statement, Part BB.
[5] Data reported in Advice Letter 1191-E-A.
[6] Data reported in Advice Letter 1256-E.
[7] Data reported in Advice Letter 1345-E-A.
[8] Data reported in Advice Letter 1414-E.
[9] Data reported in Advice Letter 1494-E.

III. PBR Distribution Net Revenue Sharing Mechanism

A. Description

The PBR Distribution Net Revenue Sharing Mechanism comprises the principal financial element of SCE's Distribution PBR mechanism.[10] This mechanism establishes a benchmark based on SCE's authorized return on common equity and puts SCE shareholders at risk for variations within 50 basis points of this benchmark. When results vary from the benchmark by more than 50 basis points, the net revenues are shared between SCE shareholders and customers.

This part of the Performance Report provides SCE's financial results for distribution operations under PBR. This information is then used to calculate a return on equity for determining net revenue sharing.

B. Results of Operations

Financial data from the 12-month period ending December 31, 2001 are presented in this section. Table III.B.1 provides SCE's financial results for its Distribution PBR. Distribution PBR operating revenues are derived from SCE's tariffed distribution rates, $43.947 million that is transferred to recorded 2001 PBR revenue from SCE's EDRABA, and Other Operating Revenues.[11] Revenues were excluded that have their own ratemaking mechanisms such as flexible pricing option contracts. The incremental revenues from non-tariffed products and services subject to the Gross Revenue Sharing Mechanism approved in D.99-09-070, as provided in SCE's Preliminary Statement, Part G, were also excluded.

PBR Distribution expenses were derived by excluding generation and ISO-related costs. This is reported in Column 1 of Table III.B.1. Those items identified as PBR exclusions are also removed. This includes the removal of costs that receive separate balancing account treatment. The incremental costs associated with non-tariffed products and services subject to the Gross Revenue Sharing Mechanisms approved in D.99-09-070 were also excluded. Column 2, labeled "PBR Distribution – Jurisdictional," presents retail customers' results of

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[10] Effective with the approval of Advice Letters 1619-E and 1619-E-A, the PBR Distribution Rate Revenue Sharing Mechanism is now termed the PBR Distribution Net Revenue Sharing Mechanism. See SCE's Preliminary Statement, Part CC.

[11] The $43.947 million in EDRABA revenue is the additional revenue that results from balancing account treatment for the difference between recorded revenue and revenue requirement for the period June 14 through December 31, 2001 (D.02-04-055, Ordering Paragraphs 2 and 3). See also footnote 3 on page 2 of this report.

operations. The separation used to identify the retail component of Column 2 is based on the 1995 GRC retail jurisdictional factor of 99.95%.

Table III.B.1, Results of Operations Report

(Table on following page)

TABLE III.B.1
SOUTHERN CALIFORNIA EDISON COMPANY
PBR RESULTS OF OPERATIONS REPORT
12 Months Ended December 31, 2001
(Thousands of Dollars)

Description	PBR Distribution System	PBR Distribution Jurisdictional
	(1)	(2)
Operating Revenues:		
Total Revenue	1,963,501	1,963,501
EDRABA Revenue [1]	43,947	43,947
Subtotal	2,007,448	2,007,448
Other Operating Revenue	112,083	112,027
Total Operating Revenues	2,119,530	2,119,474
Operating Expenses: [2]		
Fuel		
Purchased Power		
Power Exchange		
Prov-Reg Adj. Clause		
Subtotal	0	0
Production Other	0	0
Transmission (Non-ISO)	75,215	75,178
Distribution	281,749	281,609
Customer Accounts	224,199	224,087
Uncollectibles	6,286	6,282
Cust. Serv & Info	29,080	29,065
Administrative & General	143,947	143,875
Franchise Fees	19,596	19,586
Subtotal	780,073	779,682
Depreciation	478,234	477,995
Taxes Other	64,303	64,271
Taxes Income	256,493	256,364
Subtotal	320,796	320,636
Total Operating Expenses	1,579,103	1,578,313
Net Revenue	540,428	541,161
Rate Base	6,054,552	6,051,525
Rate of Return	**8.93%**	**8.94%**

Note:

[1] EDRABA is the Electric Distribution Revenue Adjustment Balancing Account filed in Advice Letter 1619-E and 1619-E-A in compliance with Ordering Paragraph 3 of D.02-04-055. Advice Letters 1619-E and 1619-E-A were approved on June 17, 2002.

[2] Pensions and Benefits expenses and Payroll Taxes are assigned to direct operating expense categories (e.g., Transmission, Distribution, Customer Accounts) instead of being shown in the Administrative & General and Other Taxes categories, respectively.

SCE's capital structure, as used for determining the PBR Distribution Return on Equity, is listed in Table III.B.2.

Table III.B.2

Capital Structure (Utility)[12]	
	Capital Ratio
Long-Term Debt	47 %
Preferred Stock	5 %
Common Equity	48 %

The Recorded PBR Distribution Return on Equity is calculated by subtracting SCE's costs of providing distribution services (including income taxes and a component for Franchise Fees and Uncollectible Accounts expense) from the distribution-related revenues received by SCE and then dividing by the Recorded PBR Distribution Common Equity.

Table III.B.3

Recorded PBR Distribution Return on Equity			
a.	Distribution-related revenues from Table III.B.1, preliminary:		2,119,474
b.	Distribution-related costs from Table III.B.1, plus	1,578,313	
	Synchronized Interest (Auth WTCD)	217,298	
	Preferred Debt (Auth Pref):	20,031	
			1,815,642
c.	Recorded PBR Distribution Common Equity = Recorded PBR Distribution Rate Base (from Table III.B.1) x Fractional Share of Common Equity (percent from Table III.B.2):		2,904,732
d.	Preliminary PBR Distribution Return on Equity = (line a - line b) / line c :		10.46 %

[12] Decision No. 96-11-060, p. 33.

C. Quantification of Net Revenue Sharing Mechanism Results

To determine the net revenues, if any, to be shared with customers requires a comparison of the 2001 Recorded PBR Distribution Return on Equity with the Benchmark Return on Equity. SCE's 2001 Recorded PBR Distribution Return on Equity of 10.46% was provided above in Section III.B. The Benchmark Return on Equity is shown below in Table III.C.1.

Table III.C.1

Benchmark Return on Equity[13]	
Benchmark Return on Equity, 2001	11.60 %

The net revenues to be shared with customers are calculated in Table III.C.2 as follows:

Table III.C.2, Net Revenue Sharing Calculation

(Table on following page)

[13] D.96-09-092, p.66, and Preliminary Statement Part CC, Section 2.

TABLE III.C.2
NET REVENUE SHARING CALCULATION
TWELVE MONTHS ENDING DECEMBER 2001

NET REVENUE SHARING CALCULATION ($000s)	
1. **Recorded PBR Distribution Rate Base:**	
2. Recorded Rate Base	6,051,525
3. **Recorded PBR Distribution Common Equity:**	
4. Authorized Common Equity	48.00%
5. Recorded PBR Distribution Common Equity	2,904,732
6. **Recorded PBR Distribution Return on Equity:**	
7. Distribution-related Revenues including	
8. EDRABA revenue	2,119,474
9. Distribution-related Expenses	1,578,313
10. Synchronized Interest (Auth WTCD)	217,298
11. Preferred (Auth Pref)	20,031
12. Subtotal	1,815,642
13. Recorded PBR Distribution ROE	10.46%
14. Benchmark Return on Equity	11.60%
15. Equity Return Variance **(ERV)**	**1.14%**
16. If ERV is greater than 0.5% but less than 3.0%	0.50%
17. Ratepayer Equity Sharing Percent **(RESP)**	**0.64%**
18. Ratepayer Equity Factor **(REF)**	**0.42%**
19. Net to Gross Multiplier	1.8045
20. Net Revenue Subject to Sharing	**(21,942)**

Note:

1. EDRABA revenue: See footnote 1 on page 8 of this report.
2. The Equity Return Variance **ERV** = Line 13 minus Line 14; the value of the **ERV**, if less than zero, is multiplied by -1.
3. If the **ERV** (Line 15) is less than or equal to 0.5% (50 basis points) then no sharing is applicable and lines 17, 18 and 20 are zero.
4. The Ratepayer Equity Sharing Percent, **RESP** = Line 15 minus Line 16, or zero if line 15 is less than 0.5% (50 basis points).
5. The Ratepayer Equity Factor, **REF** = [(Line 17) x 0.75] minus [(Line 17) x (Line 17) x 15], as provided in Edison's Tariff, Preliminary Statement Part CC, Section 3.
6. If the **ERV**, (Line 15), is greater than 3.00% (300 basis points), the **REF,** (Line 18), shall equal 0.9375 percent. The **RESP,** (Line 17), cannot exceed 2.50%.
7. The **Net-to-Gross Multiplier**, (Line 19), is 1.8045 as adopted in Decision , D.96-01-011.
8. The **Net Revenue Subject to Sharing**, (Line 20), = (Line 5) x (Line 18) x (Line 19). If the Recorded PBR Distribution ROE, (Line 13), is less than the Benchmark PBR Distribution ROE, (Line 14), then multiply the value in (Line 20) by -1.

D. Summary of Sharing Mechanism Results

SCE's financial performance resulted in a PBR Distribution Return on Equity of 10.46%. As previously shown, this Return on Equity (ROE) is 114 basis points below the benchmark ROE. Thus, SCE's financial results under the PBR mechanism is within the net revenue sharing band (-50 to -300 basis points). Based on the above calculations using the PBR Distribution Net Revenue Sharing Mechanism, the 2001 net revenue sharing is $(21.942) million. Thus, in accordance with D.96-09-092, the net revenue sharing amount for 2001 will be recorded in the PBR Distribution Revenue Requirement Performance Memorandum Account. This memorandum account is described in Resolution E-3514 and Part N of SCE's Preliminary Statement.

IV. Service Quality Performance Mechanism

A. Description

The Service Quality Performance Mechanism consists of incentives for customer satisfaction, service reliability, and employee health and safety. The determination of rewards and penalties for these measures are presented in the following sections.

B. Customer Satisfaction Measure

The Customer Satisfaction Rating measures overall customer satisfaction with SCE's service. This rating is determined annually based on the results of a survey conducted by an outside consultant. The Customer Satisfaction Rating is expressed as the percent of customer responses (rounded to the nearest percent) in the top two of six response categories in the Customer Satisfaction Survey ("completely satisfied" and "delighted" categories). The Customer Satisfaction Rating used to determine any reward or penalty is the average of the customer responses (rounded to the nearest percent) in the top two of six response categories of four measured customer service functions:

1) Field Service and Meter Reading Activities;
2) In-Person Services;
3) Telephone Center Operations; and
4) Service Planning Activities.

In Application No. 97-12-047, as amended on April 3,1998, SCE requested Commission approval to modify the measurement of customer satisfaction to incorporate survey results from In-Person Services. In-Person Services includes business transactions previously performed at local offices and now performed at additional facilities called Authorized Payment Agencies.[14] In D.98-07-077, the Commission adopted SCE's request on an interim basis and, in D.99-12-035, the Commission confirmed that the methodology adopted in D.98-07-077 is

[14] Authorized Payment Agencies are local businesses (drug stores, check cashing, etc.) that process payments in conjunction with a third-party vendor who handles the banking and data transfer to SCE for account posting.

applicable through 2001.[15] The methodology for calculating In-Person Services was affirmed in D.01-04-040.

Maritz Marketing Research, Inc., an independent market research company headquartered in St. Louis, Missouri, administered SCE's Customer Satisfaction Survey. Maritz adheres to industry guidelines (Council of American Survey Research Organizations (CASRO)) with respect to maintaining confidentiality and objectivity in data collection and reporting. In accordance with CASRO guidelines, surveys were verified by spot checks of no fewer than 15 percent of all surveys completed.

C. Customer Satisfaction Results

The Customer Satisfaction Survey for 2001 resulted in an average of 71% of SCE customers' responding in the "completely satisfied" and "delighted" rankings for SCE's service. This is shown in Table IV.C.1 as follows:

Table IV.C.1

(Table on following page)

[15] The In-Person services category uses the same five transactions originally measured in the Local Office Operations (original category title from Advice Letter 1191-E-A) category – turn-ons/turn-offs, credit/extensions, payments, deposits, and reconnects – but now is weighted based on customers served at Authorized Payment Agencies and remaining local offices.

Table IV.C.1

Customer Satisfaction Survey Results Percentage "Completely Satisfied" and "Delighted" 2001	
Field service and meter reading activities	67 %
In-person services[16]	73 %
Telephone center operations	67 %
Service planning activities	78 %
Average of "completely satisfied" and "delighted" responses	**71 %**

A reward is earned (penalty assessed) annually for a Customer Satisfaction Rating above 67% (below 61%). With the Customer Satisfaction Rating of 71%, a reward was earned for the year as shown in Table IV.C.2:

Table IV.C.2

(Table on following page)

[16] In accordance with D.01-04-040, the score for In-Person Services was calculated using the method adopted in D.98-07-077.

Table IV.C.2

Customer Satisfaction Reward (Penalty)	
Cust. Satisf. Rating	Reward (Penalty) (in millions)
72% or higher	$ 10
71%	**$ 8**
70%	$ 6
69%	$ 4
68%	$ 2
67% to 61%	$ 0
60%	$(2)
59%	$(4)
58%	$(6)
57%	$(8)
56% or lower	$(10)

Separate from the Customer Satisfaction Survey Penalty, a Floor Penalty may be assessed if the measured customer response for “completely satisfied” and “delighted” rankings in any of the four customer service functions, rounded to the nearest percent, is less than 56%. The Floor Penalty is assessed based on the lowest performing area. The Field Service and Meter Reading Activities and the Telephone Center Operations both had a Customer Service Ratings of 67%. Therefore, a Floor Penalty was not assessed for 2001.

Table IV.C.3

Floor Penalty	
Cust. Satisf. Rating	Floor Penalty (in millions)
56% or higher	**$ 0**
55%	$(2)
54%	$(4)
53%	$(6)
52%	$(8)
51% or lower	$(10)

A reward for Customer Satisfaction, as described above, is not applicable if either of the following conditions apply:

1) The average number of responses across the four customer service functions reflect more than 10% of the customer responses (rounded to the nearest percent) in the bottom two of the six categories, or
2) A Floor Penalty is assessed.

The average number of responses across the four customer service functions, in the bottom two of the six response categories, was 6% and therefore did not exceed the first condition. As described above, no Floor Penalty was assessed. Therefore, neither condition 1 nor condition 2 listed above was applicable for 2001. With overall Customer Satisfaction Survey results of 71%, SCE earned a Customer Satisfaction reward of $8 million for 2001.

D. Reliability Measures

Average Customer Minutes of Interruption (ACMI)

The ACMI measures customer service interruptions in terms of the average minutes of service interruptions per customer excluding all events that have a duration of more than five (5.0) minutes of ACMI in a 24 hour period. The ACMI is calculated as the rolling average of two successive years. The ACMI has a performance standard of 59 minutes for the initial year of operation for SCE's Nongeneration PBR Mechanism (1997) and declines by two minutes per year thereafter through 2001. The standard has a deadband of 6 minutes on both sides in which there is no reward or penalty.

Outage Frequency

The Outage Frequency measures the number of circuit interruptions excluding all events that contribute interruptions which have a duration totaling more than five (5.0) minutes of ACMI in a 24 hour period. The Outage Frequency Performance Rating is calculated as the rolling average of two successive years. The Outage Frequency has a performance standard of 10,900 interruptions with a deadband of 1,100 on both sides in which there is no reward or penalty.

E. Reliability Results

The ACMI reliability measure was 52 minutes for 2001.[17] As the ACMI reliability measure requires a rolling average of two successive years, and given that the 2000 figure was 48 minutes ACMI, the two-year rolling average to be used in determining whether a reward is earned or penalty assessed is 50 minutes ACMI as shown in Table IV.E.1.[18]

Table IV.E.1

Average Customer Minutes of Interruption (ACMI), Two-Year Rolling Average	
ACMI:	50 Minutes

A reward will be earned (penalty will be assessed) annually for a two-year rolling average ACMI measurement that is outside of the deadband for the year, as shown in Table IV.E.2 on the following page. Because the ACMI index from Table IV.E.1 was between 46 and 58 minutes, no reward was earned or penalty assessed for 2001.

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[17] Total ACMI for 2001 was 60.8 minutes less 8.7 minutes recorded for the ISO-directed outages on 3/19/01, 3/20/01, 5/7/01, and 5/8/01. This resulted in an ACMI of 52.1 minutes or 52 minutes rounded to the nearest minute. ISO-directed outages were excluded in accordance with D.98-07-077, Conclusion of Law number 1.

[18] When a distribution circuit outage occurs, field personnel manually log the event and compile related information about the event, including when the outage ends and the reason for the outage. That information is subsequently transferred to the database used to calculate SCE's performance with respect to the PBR system reliability standards adopted by the Commission in D.96-09-092. In the past several years, SCE has implemented a number of process changes to improve the accuracy and completeness of its distribution circuit outage data. We believe that these process improvements have resulted in fewer instances where outage information is not transferred to the database, compared to the prior data collection process. This may be causing our reported ACMI and circuit outage frequencies to be overstated (higher) relative to the historic performance that was used to set the PBR system reliability standards.

Table IV.E.2

2001 Service Reliability Reward (Penalty) 2-Year Average ACMI Measure (In Minutes)	
	(in millions)
28 or less	$ 18
29	$ 17
30	$ 16
31	$ 15
32	$ 14
33	$ 13
34	$ 12
35	$ 11
36	$ 10
37	$ 9
38	$ 8
39	$ 7
40	$ 6
41	$ 5
42	$ 4
43	$ 3
44	$ 2
45	$ 1
46 to 58	**$ 0**
59	$(1)
60	$(2)
61	$(3)
62	$(4)
63	$(5)
64	$(6)
65	$(7)
66	$(8)
67	$(9)
68	$(10)
69	$(11)
70	$(12)
71	$(13)
72	$(14)
73	$(15)
74	$(16)
75	$(17)
76 or more	$(18)

If an ACMI of 55 minutes or less (rounded to the nearest minute) is achieved over the 5-year PBR cycle (1997 - 2001), any penalty assessed during that period shall be reversed. The ACMI over the period 1997 – 2001 was 54 minutes. However, there was no penalty applicable for any of the years in the period.

The Outage Frequency reliability measure was 9,004 for 2001.[19] Because Outage Frequency is calculated as a rolling two-year average, and given that the 2000 Outage Frequency was 9,116, the two-year rolling average to be used in determining whether a reward is earned or penalty assessed is a frequency index of 9,060 as shown in Table IV.E.3.[20]

Table IV.E.3

Outage Frequency, Two-Year Rolling Average	
Outage Frequency:	9,060

A reward will be earned (penalty will be assessed) annually for a two-year rolling average Outage Frequency Performance Rating that is below 9,800 (above 12,000). Based on the Outage Frequency Index from Table IV.E.3, SCE earned a reward of $5 million for the year 2001 as shown in Table IV.E.4 on the following page.

[19] This figure is SCE's total frequency figure of 9,767 less 763 interruptions recorded for the ISO-directed outages on 3/19/01, 3/20/01, 5/7/01, and 5/8/01. ISO-directed outages were excluded in accordance with D.98-07-077, Conclusion of Law number 1. Note that on 3/19/01, the 5 ACMI exclusion threshold was reached for the ISO-directed outages alone. An additional 14 interruptions associated with routine distribution system outages also occurred that date but was not excluded.
[20] See footnote 18, above.

Table IV.E.4

Outage Frequency Reward (Penalty)	
Outage Frequency Performance Rating	Reward (Penalty) (In millions)
6,682 or less	$ 18
6,683 to 6,866	$ 17
6,867 to 7,049	$ 16
7,050 to 7,232	$ 15
7,233 to 7,416	$ 14
7,417 to 7,599	$ 13
7,600 to 7,782	$ 12
7,783 to 7,966	$ 11
7,967 to 8,149	$ 10
8,150 to 8,332	$ 9
8,333 to 8,516	$ 8
8,517 to 8,699	$ 7
8,700 to 8,882	$ 6
8,883 to 9,066	**$ 5**
9,067 to 9,249	$ 4
9,250 to 9,432	$ 3
9,433 to 9,616	$ 2
9,617 to 9,799	$ 1
9,800 to 12,000	$ 0
12,001 to 12,183	$(1)
12,184 to 12,367	$(2)
12,368 to 12, 550	$(3)
12,551 to 12,733	$(4)
12,734 to 12,917	$(5)
12,918 to 13,100	$(6)
13,101 to 13,283	$(7)
13,284 to 13,467	$(8)
13,468 to 13,650	$(9)
13,651 to 13,833	$(10)
13,834 to 14,017	$(11)
14,018 to 14,200	$(12)
14,201 to 14,383	$(13)
14,384 to 14,567	$(14)
14,568 to 14,750	$(15)
14,751 to 14,933	$(16)
14,934 to 15,117	$(17)
15,118 or more	$(18)

F. Employee Health and Safety Measure

Rewards or penalties for employee safety are determined based on SCE's performance related to the frequency of all industrial injuries and illnesses. The Employee Health and Safety Rating is measured in terms of the number of injuries and illnesses per 200,000 hours worked. This frequency rate, or index number, is normalized by using the factor of 200,000, which represents the average number of hours worked by 100 full-time workers in one year (40 hours per week for 50 weeks a year). The expression for this is as follows:

$$\begin{matrix} \textit{Frequency Rate} \\ (\textit{Index}) \end{matrix} = \frac{\textit{Number of incidents} \times 200{,}000\,(\textit{normalizing factor})}{\textit{Actual workhours}}$$

Expressing the index in this normalized manner is necessary to enable valid comparisons of the injury and illness statistic, from year to year, against the mechanism standard described in the next section. The index is rounded to the nearest first decimal.

G. Employee Health and Safety Results

SCE's Employee Health and Safety Rating is 4.6 for 2001, as shown in Table IV.G.1:

Table IV.G.1

Employee Health and Safety Index, 2001	
Number of injuries and illnesses:	509
X 100 employees at 2,000 hours/year:	200,000
= injuries and illnesses, statistic X employee-hours/year per 100 employees:	101,800,000
÷ Total utility employee-hours per year:	22,164,904
= Index:	4.6 per 200,000 hours worked

A reward is earned (penalty assessed) annually for an Employee Health and Safety Rating that results in an index below 12.7 (above 13.3), as shown in Table

IV.G.2, below. Since the Employee Health and Safety Index was below 11.8, SCE earned a reward for the year 2001 of $5 million as shown in Table IV.G.2.

Table IV.G.2

Employee Health and Safety Reward (Penalty)	
Employee Health and Safety Index (per 200,000 hours worked)	Reward (Penalty) (In thousands)
11.8 or less	**$ 5,000.0**
11.9	$ 4,444.4
12.0	$ 3,888.9
12.1	$ 3,333.3
12.2	$ 2,777.8
12.3	$ 2,222.2
12.4	$ 1,666.7
12.5	$ 1,111.1
12.6	$ 555.6
12.7 to 13.3	$ 0
13.4	$(555.6)
13.5	$(1,111.1)
13.6	$(1,666.7)
13.7	$(2,222.2)
13.8	$(2,777.8)
13.9	$(3,333.3)
14.0	$(3,888.9)
14.1	$(4,444.4)
14.2 or more	$(5,000.0)

H. Summary of Service Quality Performance Results

Table IV.H.1 summarizes SCE's Service Performance Mechanism results for 2001:

Table IV.H.1

Summary of Service Quality Performance Results 2001	
Customer Satisfaction Measure	Reward = $8 million
Reliability Measure, ACMI	$0
Reliability Measure, Frequency	Reward = $5 million
Employee Health and Safety Measure	Reward = $5 million
Total	Net Reward = $18 million

In accordance with D.96-09-092 and D.97-10-057, the net reward will be recorded in the PBR Distribution Rate Performance Memorandum Account. This memorandum account is described in Resolution E-3514 and SCE's Preliminary Statement, Part N.

V. Cost of Capital Trigger Mechanism

A. Description

In D.96-09-092, the Commission directed SCE to implement a Cost of Capital Trigger Mechanism (Trigger Mechanism). The Trigger Mechanism was established to adjust SCE's Authorized Return on Equity for changes in interest rates and to adjust PBR Distribution Base Rates to account for changes in the Authorized Return on Equity.

The Trigger Mechanism uses an index which tracks changes in Aa utility bond rates. In implementing the Trigger Mechanism, SCE selected Moody's Long Term Corporate Bond Yield Average for Aa Public Utilities which is reported in "Moody's Credit Perspectives," a publication of Moody's Investor Service. The Commission ordered SCE to track the monthly composition of this index in its annual report (D.96-09-092, p. 40).

B. Composition of the Cost of Capital Trigger Mechanism Bond Index

Table V.B.1 lists the bonds that made up Moody's Long Term Corporate Bond Yield Average for Aa Public Utilities, as reported in Moody's "Credit Survey" and on Moody's Internet Web site.[21]

Table V.B.1

(Table on following page)

[21] Moody's "Credit Survey" ceased publication on January 29, 2001 and SCE has not located any other published source of this information for the period between January 29, 2001 and the end of 2001.

Table V.B.1

Composition of the Cost of Capital Trigger Mechanism Bond Index				
			Moody's Bond Rating	
			Beginning	End
Company Name	Coupon	Maturity	2001	2001
Bonds Included in the Index at the Beginning and End of 2001				
Bell Telephone Company of Pennsylvania	7.375%	03/15/2033	Aa1	Aa2
Florida Power & Light Co.	7.050%	12/01/2026	Aa3	Aa3
Illinois Bell Telephone Co.	7.250%	03/15/2024	Aa1	Aa2
Michigan Bell Telephone Co.	7.500%	02/15/2023	Aa1	Aa2
Bonds Removed from the Index During 2001				
Dayton Power & Light Co.	7.875%	02/15/2024	Aa3	
Duke Energy Corp.	7.375%	03/01/2023	Aa3	
Duke Energy Corp.	6.750%	08/01/2025	Aa3	
Florida Power & Light Co.	7.000%	09/01/2025	Aa3	
Florida Power Corp.	7.000%	12/01/2023	Aa3	
National Rural Utilities Coop. Fin.	7.350%	11/01/2026	Aa3	
New England Tel. & Tel. Co.	6.875%	10/01/2023	Aa2	
Northern States Power Co. Wisconsin	7.375%	12/01/2026	Aa3	
Southwestern Bell Telephone Co.	7.625%	03/01/2023	Aa3	
Southwestern Bell Telephone Co.	6.625%	09/01/2024	Aa3	
US West Communications Inc.	6.875%	09/15/2033	Aa3	
US West Communications Inc.	7.125%	11/15/2043	Aa3	
Wisconsin Electric Power Co.	7.750%	01/15/2023	Aa2	
Bonds Added to the Index During 2001 and Included at the End of 2001				
Chesapeake & Potomac Telephone Co., VA	7.000%	07/15/2025		Aa2
Duke Energy Corp.	7.000%	07/01/2033		Aa3
Florida Power & Light Co.	7.050%	12/01/2026		Aa3
New Jersey Bell Telephone Co.	7.250%	03/01/2023		Aa2
Pacific Bell	7.375%	06/15/2025		Aa3
Southwestern Bell Telephone Co.	7.375%	07/15/2027		Aa2
Wisconsin Electric Power Co.	6.875%	12/01/2095		Aa3

In a November 1, 2001 letter to Mr. Paul Clanon of the Energy Division, SCE reported the Aa Utility Bond rate for the 12-month period ending September 2001 was 7.69 percent, which is less than 100 basis points above the current Trigger Value of 7.50 percent, as set forth in SCE's Preliminary Statement DD, Section 3.e. Thus, the Trigger Mechanism was not activated to cause a change to SCE's Authorized Return on Equity.[22]

VI. Data on Failures of Distribution Facilities Listed in General Order 165 and Cable Connections

In Decision No. 98-08-015, the Commission directed SCE to report the frequency of circuit interruptions resulting from the failure of the types of equipment listed in General Order (G.O.) 165 and cable connections. SCE reports this information in Table VI.1.[23] This data excludes all circuit interruptions occurring during events that have a circuit interruption duration totaling more than five (5.0) minutes of ACMI.

Table VI.1

Number of Non-Catastrophic Circuit Interruptions Resulting from Equipment Failure (By Distribution Equipment Type Listed in G.O. 165)

2001

G.O. 165 Facility Type	
Transformers	108
Switching/Protective Devices	347
Regulators/Capacitors	12
OH Conductors	196
UG Cables	398
UG Terminations	124
Streetlighting	4
Wood Poles	22

[22] In D.01-06-038, the Commission modified D.96-09-092 to extend SCE's PBR mechanism until superseded by SCE's 2003 General Rate Case. Pursuant to the Proposed Decision in SCE's Expedited Petition for Modification of D.96-09-092, the Cost of Capital Trigger Mechanism would extend through 2002. A Commission decision in the case is pending.

[23] Effective August 1998, SCE modified its internal outage reporting guidelines to better identify instances in which structure or equipment failure (including cable connections) cause a circuit interruption. The revised procedures require that an Equipment and Maintenance (E&M) Engineer review and validate equipment failures, complete material failure reports, and investigate incomplete or questionable data. Final validation of the outage report by the E&M Engineer ensures that the cause codes of the circuit interruptions have been accurately recorded.

VII. Data Reporting Commitments Adopted in Decision Number 99-12-035

In Decision No. 99-12-035, the Commission directed SCE to report data relative to busy conditions on inbound customer telephone trunk lines, streetlight repairs, service guarantee commitments, and customer service erroneous disconnects. In Tables VII.1 and VII.2, SCE reports this information for 2001.

SCE's service guarantee program is a voluntary program funded by shareholders. On January 15, 2001, SCE discontinued service guarantees as a result of resource limitations imposed by the energy crisis.

Table VII.1

Street Light Outage Data	
On an annual basis, for the street light outages not caused by a source energy feed problem (e.g., broken cable), the percentage of streetlights repaired within three working days and the percentage repaired within five working days.[24]	
Repairs made within three working days:	97.2%
Repairs made within five working days:	99.5%
On an annual basis, for street light outages caused by a source energy feed problem (e.g., broken cable), the percentage of streetlights repaired within 17 working days.	
Repairs made within 17 working days:[25]	72.5%

[24] Based on the time between when a customer reports a streetlight out and when the streetlight is repaired or replaced. Streetlight repairs made when customers have not reported an outage are not included.

[25] This statistic reports permanent repairs made within 17 days. When including temporary repairs with permanent repairs, over 95% of streetlights that had source feed problems were restored to operation within 17 days. This reflects SCE's repair practice as modified in 2000. In the case of source energy feed problems, SCE now performs temporary repairs in order to promptly restore service. Permanent repairs are then completed during a follow-up visit by an electrical contractor.

Table VII.2

Table VII.2
PBR Data Reporting and Gathering Requirements (D.99-12-035)
Year: 2001

Call Center Performance

Percentage of time all primary inbound trunk lines at SCE's call centers are busy	
Jan-01	0.01%
Feb-01	0.00%
Mar-01	0.16%
Apr-01	0.00%
May-01	0.01%
Jun-01	0.00%
Jul-01	0.00%
Aug-01	0.00%
Sep-01	0.00%
Oct-01	0.01%
Nov-01	0.01%
Dec-01	0.02%

Service Guarantee Program **

	Annual Number	Annual Amount Paid Out
Service guarantees not met 1. New Meter Installation and Service Initiation	--	--
2. Responding Quickly to Service Disruptions	46	$2,300
3. Restoring Service Within 24 Hours of Notification	8	$400
Total	54	$2,700

Erroneous Disconnects

	Annual
Number of occurrences in which a customer's service was erroneously disconnected Total	1,039
Credit-related	1,036
Percentage of erroneous disconnects as a percentage of disconnects*	0.23%

* This percent is credit-related disconnects in error versus total credit-related disconnects. Erroneous disconnects can also occur as a result of a turn-off order. Adding turn-off orders into this calculation is not meaningful because a turn-off order is not generally a disconnect. It is instead either matched to a turn-on order or is simply a meter read.

** Due to the resource limitations imposed by California's energy crisis, this voluntary program was suspended beginning on January 15, 2001.

ANNEX E: EXAMPLE OF A PERFORMANCE AGREEMENT – SAN DIEGO GAS & ELECTRIC COMPANY PERFORMANCE AGREEMENT

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

A. PURPOSE OF MECHANISM

The Electric Distribution and Gas Performance-Based Ratemaking ("Distribution PBR") Mechanism will adjust base rates pursuant to calculations related to the rate indexing formula, and include mechanisms for revenue sharing and performance incentives as described herein.

B. EFFECTIVE DATE

The Distribution PBR Mechanism became effective on January 1, 1999, and will remain in effect during 1999-2002. The PBR mechanism is subject to the suspension provisions contained in Section E. The Distribution PBR was approved by Commission Decision 99-05-030, dated May 13, 1999. The initial revenue requirements and rates were approved by D.98-12-038, dated December 17, 1998.

C. DEFINITIONS

1. Subject Year: The calendar year for which PBR rates are determined and PBR performance is evaluated.

2. Prior Year: The year immediately prior to the Subject Year.

3. 1999 Cost of Service Proceeding: References to the utility's adopted 1999 Cost of Service (COS) will be Decision 98-12-038, which approved the all-party settlement of the utility's 1999 Cost of Service proceeding.

4. Net Operating Income (NOI) subject to sharing is combined Electric and Gas Net Operating Income as reported in the "Results of Operations" CPUC Form 074 dated December 31 of the Prior Year, column entitled "Adjusted to Distribution PBR". NOI subject to sharing, an after-tax figure, is adjusted to remove the effects of Demand Side Management (DSM) Rewards, PBR Rewards/Penalties, and certain other exclusions as described in Section K.4.

5. Rate of Return (ROR) subject to sharing is NOI subject to sharing divided by Rate Base, as reported in the "Results of Operations" CPUC Form 074 dated December 31 of the Prior Year, column entitled "Adjusted to Distribution PBR". ROR subject to sharing is adjusted to remove the effects of DSM Rewards, PBR Rewards/Penalties and certain other exclusions as described in Section K.4.

6. Authorized Rate of Return (ROR) is the rate of return authorized for the utility by the Commission in the annual Cost of Capital proceeding and adjusted for, if necessary, the utility's Market Index Capital Adjustment Mechanism (MICAM).

7. MICAM will annually adjust the utility's cost of capital based on market changes in a composite of utility bond rates when the mechanism is triggered.

8. Indexing Formula: Formula used to annually adjust rates by applying to each rate component the annual escalation (inflation) factor less the productivity factor. Revenue changes, such as amounts from earnings sharing or other adjustments, will be applied to rates as a percentage change to each component.

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

C. DEFINITIONS (Continued)

9. DRI/McGraw-Hill Utility Cost Information Service (DRI-UCIS): The utility will use the most recent historical and forecasted data available from Standard & Poor's DRI-UCIS in developing the escalation factors used to adjust the subsequent year's electric distribution and gas base rates. Separate cost indices are used for electric and gas and are weighted according to their labor, non-labor and capital-related components. The weights used to construct the weighted average are based on average state-level electric distribution or gas utility expenditures.

10. Productivity Offset (X Factor): The productivity factors, which are applied separately for electric and gas, are based on a national utility industry analysis of productivity. They will be applied as an offset to the annual escalation in the indexing formula.

11. Material External Events (Z Factor): Pursuant to D.99-05-030, Z Factors must meet the criteria established in D.96-09-092 to be determined recoverable as an adjustment to the annual update rule. A $5 million deductible is applied to each qualifying Z Factor event.

12. Occupational Safety and Health Administration (OSHA) Reportable Injury and Illness Index: The employee safety performance indicator is based on an OSHA frequency standard, measuring the utility's OSHA-reportable lost time and non-lost time injuries and illnesses. The number of injuries and illnesses are measured as required by OSHA Log and Summary of Occupational Injuries and Illnesses (OSHA log 200).

13. Total Company Workhours: The total hours worked by all employees during a calendar year as reported in U.S. Department of Labor, Bureau of Labor Statistics' Survey of Occupational Injuries and Illnesses.

14. Electric Reliability Performance Indicators:
The Distribution PBR utilizes three performance indicators that measure the reliability of the electric service provided to customers. Each benchmark excludes planned outages, Major Events and events that are the direct result of failures in the Independent System Operator (ISO) controlled bulk power market or other transmission facilities not owned by the utility. The annual performance measures will be based on the figures presented in the utility's Annual Electric Distribution System Performance Report. The three performance indicators are:

    a. System Average Interruption Duration Index (SAIDI) is a measure of the duration of electric service forced and sustained (duration of five minutes or more) interruptions experienced by customers each year.

    b. System Average Interruption Frequency Index (SAIFI) is a measure of the frequency of annual electric distribution system forced outages with a duration of five minutes or more.

    c. Momentary Average Interruption Frequency Index (MAIFI) is a measure of the frequency of annual electric distribution system forced outages with a duration of less than five minutes.

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

C. DEFINITIONS (Continued)

15. Major Events: A major event outage is excluded from the SAIDI, SAIFI and MAIFI measurements and is declared when condition (a) or condition (b) is met (D.96-09-045):

    a. Customer outages caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency being declared by the government.

    a. Any other event not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

16. Customer Service Monitoring System (CSMS): The CSMS indicator measures annual overall customer satisfaction with recent service transactions provided by the utility in five service segments. These are: 1) Service Order; 2) Gas Service; 3) Electric Service; 4) Customer Service Telephone Center; and, 5) Counter Services at Branch Offices.

17. Rewards and Penalties Balancing Account (RPBA): The RPBA records the amounts allocated to the electric and gas departments for the utility's rewards, penalties and PBR revenue sharing. At the end of each year, during the rate freeze transition period, the electric portion of the year-end RPBA balance will be transferred to the Transition Revenue Account (TRA). For the gas portion and the post-rate freeze electric portion, the utility shall file by October 1 of each year an advice letter requesting to apply the projected year-end RPBA balance as a twelve month amortization to electric distribution and gas rates.

D. REPORTING REQUIREMENTS

On October 1 of each year, the utility will file an advice letter detailing the adjustments to the electric distribution and gas base rates for the next year, in accordance with the adopted rate indexing formula. The advice letter will provide the calculations and workpapers supporting the escalation component of the rate indexing formula, including the application of the projected year-end balance of the RPBA. The October 1 filing will be updated to include effects of relevant Commission decisions issued subsequent to October 1 and affecting the revenue requirement at the beginning of the Subject Year (e.g., a Commission decision affecting the utility's cost of capital). The resultant electric distribution and gas rates will be scheduled to become effective beginning January 1 of each year.

On February 15 of each year, the utility shall file, by advice letter, the "Annual Distribution PBR Performance Report" for the Subject Year just ended. This filing will detail the Subject Year's Performance Indicator (Section L) and Revenue Sharing (Section K) results. Revenue sharing results and performance indicator rewards or penalties will be recorded in the RPBA (See Section M).

The utility will also submit three quarterly reports to the Commission's Energy Division and interested parties within 45 days after the end of each calendar quarter, addressing the utility's 12-months-to-date earnings sharing (through March 31, June 30 and September 30, respectively) and year-to-date performance indicator results.

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

E. SUSPENSION OF MECHANISM

The Distribution PBR Mechanism will be subject to voluntary suspension whenever the utility reports one year of NOI subject to sharing which results in a ROR subject to sharing of more than one hundred fifty (150) basis points below its authorized ROR. Either the utility or the Commission's Office of Ratepayer Advocates may file a motion seeking suspension of the mechanism. If the motion is granted by the Commission, a formal review would then be required.

The Distribution PBR will be subject to automatic suspension whenever the utility reports one year of NOI subject to sharing which results in a ROR subject to sharing of 300 or more basis points below its authorized ROR. Such suspension will trigger a formal regulatory review of the utility's PBR mechanism.

F. INITIAL RATES

The utility's base rate PBR revenue requirements for both the electric and gas departments were authorized by the Commission in D.98-12-038 which approved the settlement of utility's 1999 COS proceeding. The rates derived from the revenue requirements will be adjusted annually based on the provisions contained herein.

The initial authorized revenue requirements include the sum of operating and maintenance expenses, capital related revenues and other revenues. The initial electric distribution and gas rates were filed with the Commission in Advice Letters 1141-E and 1130-G, respectively.

G. AUTHORIZED RATE OF RETURN (ROR)

The Authorized ROR will be equal to the sum of the weighted rates of return on long term debt, preferred stock and common equity, as authorized on January 1 of the Subject Year. Additional changes from SDG&E's Market Index Capital Adjustment Mechanism (MICAM), or any subsequent approved cost of capital mechanism, will be incorporated in the corresponding annual indexing changes. The cost of capital in electric distribution and gas base rates is trued-up to the MICAM adjusted cost of capital in years when a MICAM adjustment is triggered. MICAM subjects the utility's cost of capital to annual automatic adjustments based on market changes in utility bond rates if the interest rates change by the specified amount of basis points from the previous benchmark.

The initial 1999 ROR will be a weighted result of the current ROR (9.35%) and the new ROR adopted by the Commission in the utility's 1999 Cost of Capital Proceeding (A.98-05-019).

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

H. RATE INDEXING FORMULA

The starting point for the electric distribution and gas rates was established by the 1999 authorized rates as determined through the 1999 Cost of Service proceeding. These rates are subject to any adjustments as authorized in the utility's 1999 Cost of Capital Proceeding (A.98-05-019), Post Transition Period Ratemaking Proceeding (A.99-02-029) or other applicable Commission proceeding(s). The subsequent year's electric distribution and gas base rates will be determined by applying a formula to adjust the previous rates (i.e. rates expected to be in effect at December 31 of the current year) for costs of inflation and for productivity improvements.

1. Indexing Formula

The form of indexing is referred to as "CPI minus X." The rate indexing formula is illustrated as follows:

Rate(n) = Rate(n-1) (1+Esc-X) +/- Z

where Rate = electric distribution rate component or gas base rate component

n = year for which rates are being determined

Esc = Escalation or inflation factor

X = Productivity factor

Z = Exogenous factors (Section I.)

Each rate component will be adjusted annually according to the formula to become effective on January 1 of subject year. Revenue changes, such as amounts from earnings sharing or other adjustments, will be applied to rates as a percentage change to be made to each rate component. The percentage used to change each rate component will be equal to the revenue change amount as a percentage of the current year's total authorized revenue, with an adjustment for changes in throughput during the year. For example, if a $1 million rate adjustment is to be made for electric distribution for the year 2000 when hypothetically 1999 authorized revenue was $600 million and throughput had increased by 2% during 1999, the following calculation would be made.

$1,000,000 / ($600,000,000 x 1.02) = 0.16% increase to each electric distribution rate component

2. Escalation Factor

Separate escalation factors are used for electric distribution and gas. These factors are based on California utility specific cost indices that are updated each year. The utility-specific cost indices are constructed with state-level expenditure weights. Each cost index is designed to measure changes in price levels of labor, nonlabor and capital inputs purchased by utilities. One cost index applies to electric distribution and another to gas base rates.

(Continued)

H. RATE INDEXING FORMULA (Continued)

2. Escalation Factor (continued)

a. Labor O&M Cost Escalation: The utility will use average hourly earnings for electric, gas and sanitary services (AHE49NS) as the basis for its labor cost index. The United States Bureau of Labor Statistics collects and reports historical data for this data series. The AHE49NS is the same average hourly earnings data series that the Standard & Poor's DRI/McGraw-Hill Utility Cost Information Service (DRI-UCIS) uses as the basis for the labor cost index in its electric and gas utility O&M cost model for labor, material and services.

b. Nonlabor O&M Cost Escalation: The index for electric distribution nonlabor O&M expenses utilizes five DRI-UCIS cost indices: total distribution plant O&M cost index (JEDOMMS); customer accounts operation cost index (JECAOMS); customer service and information operation cost index (JECSIOMS); sales operation cost index (JESALOMS) and total administrative and general O&M cost index (JEADGOMMS). The index for gas nonlabor O&M expenses is the DRI-UCIS total gas utility nonlabor O&M cost index (JGTOTALMS).

c. Capital-Related Cost Escalation: The cost index for capital-related electric distribution revenue is based on an estimate of the rental price of electric distribution utility structures, which is estimated from three data series obtained from DRI: rental of capital - nonresidential structures - public utilities (ICNRCOSTPU); chain type price index - investment in nonresidential structures - public utilities (PCWICNRPU); and the Handy-Whitman electric utility construction cost index - total distribution plant, Pacific Region (JUEPD@PCF). All of these indices are obtained from the DRI. The rental price of capital for electric distribution utility structures (ICNRCOSTPUED) is calculated as follows:

ICNRCOSTPUED = ICNRCOSTPU * (JUEPD@PCF / PCWICNRPU)

The cost index for capital-related gas costs is based on an estimate of rental price of gas utility structures, which is estimated from three data series obtained from the DRI: rental price of capital – nonresidential structures – public utilities (ICNRCOSTPU); chain type price index – investment in nonresidential structures – public utilities (PCWICNRPU); and the Handy-Whitman gas utility construction cost index – total plant, Pacific Region (JUG@PCF). The rental price of gas utility structures (ICNRCOSTPUG) is calculated as follows:

ICNRCOSTPUG = ICNRCOSTPU * (JUG@PCF / PCWICNRPU)

A three-year moving average of the rental price of utility structures is used to calculate the capital-related cost indices.

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

H. RATE INDEXING FORMULA (Continued)

2. Escalation Factor (continued)

d. Weighting Factors: The escalation factors for electric distribution and gas are each a weighted average of the component cost indices for labor, nonlabor and capital-related expenses. The weights used to construct the weighted average are based on average state-level electric distribution expenditures or gas utility expenditures expressed in real 1996 dollars for the period 1992-1996. These weights are shown below:

	Electric	Gas
Labor	0.179216	0.234234
Nonlabor		0.312008
Distribution	0.062799	
Customer Accounts	0.028032	
Customer Service	0.043102	
Sales	0.001225	
Admin. & General	0.109725	
Capital	0.575900	0.453757
	------------	------------
Total	1.000000	1.000000

e. Annual Escalation Calculation: Beginning in the year 2000, the percentage changes in the weighted cost indices will be used in the PBR indexing formula to adjust the electric distribution and gas base rates for changes in the cost of inputs purchased by the utility. In mid-August 1999, one-year ahead projections of the cost indices and the percentage changes in these indices will be estimated. These estimates will be based on the most recent historical and forecast data available from Standard and Poor's DRI/McGraw-Hill Economic and Utility Cost Information Services. In mid-August of every year beginning in the year 2000, historical and forecast cost indices and percentage changes in these indices will be estimated from the most recent and forecast data available from the DRI. The historical and forecast percentage changes will be used in the PBR rate indexing formula to adjust rates for the next year. Both forecast and historical percent changes back to 1999 are required to adjust rates with the most recent and accurate cost escalation estimates available after 1999. The updated historical and forecast percentage changes should capture all revisions in the DRI data used to compute the cost indices.

1. Productivity Offset (X Factor)

An annual productivity offset shall be used in the PBR Indexing Mechanism. The X factor for electric distribution is 1.32 percent in 2000, 1.47 percent in 2001 and 1.62 percent in 2002. On the gas side, the X factor is 1.08 percent in 2000, 1.23 percent in 2001 and 1.38 percent in 2002.

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PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

I. MATERIAL EXTERNAL EVENTS (Z Factor)

Z Factors are exogenous events, unexpected at the implementation of PBR, largely uncontrollable by management, having a material and disproportionate impact on the utility. These events must meet the following criteria to be determined recoverable as an adjustment to the annual update rule (D.96-09-092):

1. The event causing the cost must be exogenous to the utility.
2. The event must occur after implementation of the PBR.
3. The utility cannot control the cost.
1. The costs are not a normal cost of doing business.
2. The event affects the utility disproportionately.
3. The PBR update rule must not implicitly include the cost.
4. The cost must have a major impact on the utility.
5. The cost impact must be measurable.
6. The utility must incur the cost reasonably.

When a potential Z-factor event occurs, the utility must promptly advise the Commission of its occurrence by advice letter and establish a separate memorandum account for each event. The notification shall provide all relevant information, including a description, amount involved, timing and how the event conforms to the nine criteria. Recorded costs are charged to each subaccount at the end of each month. Revenues authorized by the Commission to amortize the balance are credited to each sub-account at the end of each month. Interest shall accrue on a monthly basis by applying the appropriate interest rate to the average of the beginning and ending balance less $5 million deductible amount which is applicable to each qualifying Z-factor event.

J. EXCLUSIONS TO INDEXING MECHANISM

In compliance with D.98-12-038 and D.99-05-030, the following items, which are included in 1999 authorized revenues, shall be excluded from the indexing mechanism before the utility calculates its annual escalation of electric distribution and gas rates:

1. Tree trimming expenses (less brush management and other non-tree trimming costs) pursuant to D.98-12-038, which are being recorded to the Tree Trimming Balancing Account (TTBA). These expenses were settled annually at $30.2 million.
2. Costs for the Natural Gas Vehicle (NGV) program of $0.3 million, which are excluded for the year 2000 update rule only. Beginning in 2001, these costs shall be included in the PBR indexing mechanism.
3. Costs of $1.2 million associated with gas research, development and demonstration (RD&D), as these are subject to a one-way balancing account.
4. Fixed A&G costs that the utility may be able to recover through contracts under which it will provide O&M services to its divested fossil fuel plants, as adopted in D.98-12-038. If the utility is able to recover any of these costs through a maintenance contract, it will make a downward adjustment to the authorized revenue requirement.
5. Year 2000 computer expenses, which were settled at $1.2 million per year.
6. Rewards associated with Demand Side Management (DSM) programs.
7. Gas Brokerage Fee that was settled at $0.903 million and is part of the gas procurement N
rates. The Gas Brokerage Fee is not subject to rate indexing since it is not a part of the gas N
transportation rates. N

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PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

K. REVENUE SHARING

The starting point for electric distribution and gas rates was determined through the adopted Settlement Agreement to SDG&E's 1999 COS proceeding (D.98-12-038). The amount from earnings sharing will be recorded to the RBPA as described in Sections D and M. The earnings available for sharing are calculated by comparing the actual net operating income to that of the authorized ROR. The difference is then subject to earnings sharing. The amount will be allocated between the electric distribution and gas revenue requirements based on the adopted allocation of 1999 total authorized base revenues (73% electric, 27% gas).

The earnings sharing mechanism shares earnings only within bands above a benchmark rate of return (ROR) on rate base. Shareholders will retain 100% of the earnings up to 25 basis points (0.25%) above the benchmark ROR and also any earnings above 300 basis points (3%). Between 25 to 300 basis points above the benchmark, there are nine bands where there will be sharing of earnings between shareholders and ratepayers as illustrated below.

1. Revenue Sharing Formula

Net Operating Income (NOI) subject to sharing (after all income tax effects have been taken into account) is as follows:

Bands	Basis Points	Shareholder %	Ratepayer %	Average Ratepayer %
Inner	00-25	100%	00%	0.00%
1	25-50	25%	75%	37.50%
2	50-75	25%	75%	50.00%
3	75-100	35%	65%	53.75%
3	100-125	45%	55%	54.00%
5	125-150	55%	45%	52.50%
6	150-175	65%	35%	50.00%
7	175-200	75%	25%	46.88%
8	200-250	85%	15%	40.50%
9	250-300	95%	05%	34.58%
Outer	300-above	100%	00%	------

To achieve the specific shareholder/ratepayer sharing set forth in the table above on a basis net of tax, the tax provision is shared such that the ratio of net benefits of shareholders to ratepayers equals (1-r)/r, where 1-r and r equal the adopted average shareholder and ratepayer sharing percentages, respectively. In order to achieve this net benefit ratio, the ratepayer credit is "grossed-up" by the factor 1/(1-r*t), where r = the average ratepayer sharing percentage and t = the combined income tax rate.

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

K. REVENUE SHARING (Continued)

2. Example Calculations

Assumptions:

Basis points above authorized ROR	=	110 (i.e. .011 above authorized ROR)
Actual Weighted Average Rate Base	=	$1,900 million
NOI above authorized = .011 * $1,900	=	$20.90 million
First sharing band = (20.9 / 110)* 25	=	$4.75 million
Combined income tax rate (t)	=	40.746% (i.e. 0.40746)

The ratepayer share before grossing up equals:

($4.75 million * 75%) + ($4.75 million * 75%) +
($4.75 million * 65%) + ($1.90 million * 55%) = $11.257 million

Since r = $11.257 / $20.90 = 0.539, the grossed-up ratepayer credit = $11.257 million / (1 – 0.539 * 0.40746) = $14.425 million

3. Exclusions to Revenue Sharing

In compliance with D.98-12-038 and D.99-05-030, the following items shall be excluded from recorded PBR base rate revenues and/or expenses before the utility calculates its actual earned ROR for revenue sharing purposes:

a. Tree trimming revenues and incurred expenses (less brush management and other non-tree trimming costs) pursuant to D.98-12-038, which are being recorded to the TTBA.

b. Recorded expenses attributable to senior executive retirement plans and executive bonuses.

c. Costs associated with the NGV program for 1999 and 2000. Beginning in 2001, these costs should be included as PBR expense for revenue sharing purposes.

d. Costs associated with gas RD&D, as this is subject to a one-way balancing account.

e. Any under run of the fixed A&G costs associated with the maintenance contract for divested fossil power plants, pursuant to the adopted settlement in D.98-12-038.

f. Hazardous waste costs, which are recovered through the Hazardous Waste Collaborative.

g. Future costs related to the Catastrophic Event Memorandum Account and the Gas Hazardous Substance Cost Recovery Account, which are recovered through those respective accounts.

h. Rewards associated with DSM programs, PBR performance indicators and Nuclear Unit Incentives.

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PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

L. PERFORMANCE INDICATORS

The total amount of electric distribution and gas performance indicator reward or penalty that may be accrued in any year of the PBR Mechanism, beginning with 1999 shall not exceed fourteen million, five hundred thousand dollars ($14.5 million). The performance reward or penalty will be based on the utility's performance in the following categories:

Performance Rewards/(Penalties) equals the sum of:

(1) Employee Safety (Section L.1.)
(2) Customer Satisfaction (Section L.2.)
(3) System Reliability (Three Indicators) (Section L.3.)
(4) Call Center Responsiveness (Section L.4.)

1. Employee Safety: Rewards or penalties for employee safety shall be based on a Federal Occupational Safety and Health Administration (OSHA) frequency standard, measuring the utility's regulated OSHA-reportable lost-time and non-lost time injuries and illnesses against total utility employee working hours. Rewards or penalties received for employee safety performance are allocated 73*% to the electric department and 27% to the gas department revenue requirements.*

a. Reward/(Penalty) Mechanism:

Rewards and Penalties shall be based on the following parameters:

Benchmark: 8.80 OSHA - reportable frequency rate

Deadband: +/- 0.20

Liveband: +/- 1.20

Unit of change: 0.01

Incentive per unit: $25,000 outside the deadband

Maximum incentive: +/- $3 million

b. OSHA Reportable Frequency Formula:

Total OSHA Reportable Frequency = Total OSHA Cases x 200,000 / Total Company Annual Work Hours.

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PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

L. PERFORMANCE INDICATORS (Continued)

2. Customer Satisfaction: Rewards or penalties for customer satisfaction will be determined based on the utility's year-to-date performance as reported in the Customer Service Monitoring System (CSMS) Results, (4th Quarter). Rewards or penalties received for customer satisfaction performance are allocated 73% electric department and 27% gas department revenue requirements.

   a. Reward/(Penalty) Mechanism: Rewards and penalties shall be based on the following parameters:

      Benchmark: 92.5% very satisfied - CSMS formula

      Deadband: +/- 0.5%

      Liveband: +/- 2.0%

      Unit of change: 0.1%

      Incentive per unit: $75,000 outside the deadband

      Maximum incentive: +/- $1.5 million

   b. CSMS Formula: Overall CSMS Average %"Very Satisfied" = Simple Average of %"Very Satisfied" cumulative Year-to-Date responses from the following service segments:

      (1) Service Order
      (2) Gas Appliance Services
      (3) Electric Service
      (4) Customer Service Call Center
      (5) Counter Service at Branch Offices

3. System Reliability: Rewards or penalties for system reliability will be determined based on the utility's performance on three separate performance indicators. These indicators are: 1) the System Average Interruption Duration Index (SAIDI) measurement, 2) the System Average Interruption Frequency Index (SAIFI); and, 3) the Momentary Average Interruption Frequency Index (MAIFI). SAIDI measures the duration of electric service forced and sustained interruptions experienced by customers each year, excluding major events and planned outages. SAIFI and MAIFI both measure the frequency of electric distribution forced outages that occur in a year, excluding major events and planned outages. SAIFI measures sustained outages (5 minutes or greater), whereas MAIFI measures momentary outages (less than 5 minutes). Rewards or penalties received for the system reliability performance indicators are allocated 100% to the electric department revenue requirements.

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L. PERFORMANCE INDICATORS (Continued)

3. System Reliability (Continued)

a. Reward/(Penalty) Mechanism: Rewards and Penalties shall be based on the following parameters:

1) SAIDI (Excluding Major Events and Planned Outages)

Benchmark: 52 minutes (excluding underground cable failures) for each year 1999, 2000 and 2001; and 73 minutes (including underground cable failures) for 2002

Deadband: 0

Liveband: +/- 15

Unit of change: 1

Incentive per unit: $250,000

Maximum incentive: +/- $3.75 million

2) SAIFI (Excluding Major Events and Planned Outages)

Benchmark: 0.90 outages per year

Deadband: 0

Liveband: +/- 0.15

Unit of change: 0.01

Incentive per unit $250,000

Maximum incentive: +/- $3.75 million

3) MAIFI (Excluding Major Events and Planned Outages)

Benchmark: 1.28 outages per year

Deadband: 0

Liveband: +/- 0.30

Unit of Change: 0.015

Incentive per unit: $50,000

Maximum incentive: +/- $1 million

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L. PERFORMANCE INDICATORS (Continued)

3. System Reliability (Continued)

a. Exclusions: The measurement of each of the electric reliability performance indicators excludes planned outages, Major Events, and events that are the direct result of failures in the ISO-controlled bulk power market or other non-utility owned transmission facilities.

Major Events are defined in D.96-09-045 as an event that meets at least one of the following criteria: 1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency being declared by the government; or, 2) an event that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

4. Call Center Responsiveness: Rewards or penalties for Call Center Responsiveness are determined by a base level measure in which 80 percent of calls will be answered within 60 seconds on a 24-hour average annual basis. This includes both personal and electronic responses to inquiries, including Customer Service Representatives and Interactive Voice Responses. Rewards or penalties received for Call Center Responsiveness performance are allocated 73% to the electric department and 27% to the gas department revenue requirements.

a. Reward/(Penalty) Mechanism: Rewards and penalties shall be based on the following parameters:

Benchmark: 80% of calls answered in 60 seconds, measured on an annual basis

Deadband: 0

Liveband: +/- 15.0%

Unit of Change: 0.1%

Incentive per unit: $10,000

Maximum incentive: +/- $1.5 million

(Continued)

PRELIMINARY STATEMENT

IV. ELECTRIC DISTRIBUTION & GAS PERFORMANCE BASED RATEMAKING (PBR) MECHANISM

L. PERFORMANCE INDICATORS (Continued)

5. Service Guarantees:

a. If the utility is unable to meet an appointment commitment with a customer for services at the customer's premises when access is required, SDG&E will credit $50 to the customer's account. Appointments can be all day or they may be made within four-hour windows (a.m./p.m.). The credit does not apply if the customer is notified at least four hours before the end of the appointment period. The guarantee does not apply for gas pilot light service or if the utility documents that the reason for the missed appointment was due to natural disaster, labor strike or the service person was called off to work on an Emergency Order. Emergency Orders are excluded as a result of the utility's public safety obligations and include the following events: 1) Fire or explosion; 2) Broken or blowing gas line; 3) High gas pressure; 4) Emergency carbon monoxide; and, 5) Hazardous leaks.

b. When an individual customer requests a date for a permanent new service establishment, the utility will turn on new service on the day promised (prior to midnight) or credit the customer's account with the appropriate Service Establishment Charge ($15 electric, $30 for both gas and electric) instead of the $50 stated above. The credit does not apply if at least 24 hours notice of a date change is given to the customer. Notice given on an answering machine or to another number designated by the customer is sufficient. For the guarantee to be valid, there must be: 1) Open access to the facility and the meter panel or gas service; 2) All required inspections must be completed and approved; and, 3) No threats or harm to utility employees.

M. REWARDS AND PENALTIES BALANCING ACCOUNT (RPBA)

1. Electric Department: Pursuant to Resolution E-3588, the utility shall record rewards and penalties and earnings sharing amounts allocated to the electric department to the RPBA. At the end of each year, during the rate freeze transition period, the annual balance of the RPBA will be transferred to the Transition Revenue Account, which is used to determine the amount of revenues available to be transferred to the Transition Cost Balancing Account (TCBA). After the rate freeze ends, the utility shall file by October 1 of each year an advice letter requesting to apply the projected year-end balance of the RPBA as a twelve month amortization to the electric distribution rate effective January 1 of the following year.

2. Gas Department: PBR rewards/penalties and earnings sharing amounts allocated to the gas department shall be recorded to the RPBA. The utility shall file by October 1 of each year an advice letter requesting to apply the projected year-end balance of the RPBA as a twelve month amortization to the gas rate effective January 1 of the following year.