Performance-based Ratemaking for Electric Utilities: Review of Plans and Resource-Planning Issues - Volume II: Appendices

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ENERGY AND ENVIRONMENT DIVISION

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Contents

Acronyms and Abbreviations

ACMI	Average customer minutes of interruption
ARP	Alternative Rate Plan
ARPC	Average revenue per customer
BLS	U.S. Bureau of Labor Statistics
CAIDI	Customer Average Interruption Duration Index
CMP	Central Maine Power
ConEd	Consolidated Edison of New York
COS/ROR	Cost of Service/Rate of Return
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPI-U	Consumer Price Index, Urban Consumers
DIRAM	DSM Incentive and Revenue Adjustment Mechanism
DSM	Demand-side management
ECI	External cost index
EIA	Energy Information Administration, U.S. Department of Energy
ERAM	Electric revenue adjustment mechanism
FAC	Fuel adjustment clause
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GNP-PI	Gross National Product-Price Index
GPNA	Gross plant net additions
IRP	Integrated resource planning
LEC	Local exchange companies
MERIT	Measured Equity Return Incentive Term (NMPC)
NERAM	Niagara Electric Revenue Adjustment Mechanism
NMPC	Niagara Mohawk Power Co.
NRS	Net resource savings
NYDPS	New York Dept. of Public Service (Staff of the NYPSC)
NYPSC	New York Public Service Commission
O&M	Operations and maintenance
PBR	Performance Based Ratemaking
PG&E	Pacific Gas & Electric Co.
PSC	Public Service Commission
PUC	Public Utility Commission
QF	Qualifying facility
ROE	Return on equity
ROR	Rate of return
RPC	Revenue per customer
RSE	Rate Stabilization and Equalization

SAB	System Average Bills
SAIDI	System Average Interruption Duration Index
SARB	System Average Rate/Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Co.
T&D	Transmission and Distribution
TEP	Tucson Electric Power

Summaries of Electric Utility PBR Plans

A.1 Introduction

This appendix contains summaries of the PBR plans we collected and reviewed in our analysis. Each section below describes the following details as they apply to each utility plan:

- the relationship of the plan to any known restructuring initiatives within the state where the utility operates;
- the term of the PBR mechanism;
- the type of mechanism and the way it works;
- the scope of the PBR mechanism and whether it covers key aspects such as fuel costs, DSM costs, and purchased power costs;
- the plan's primary incentive mechanism, including any formulas used year to year to calculate rates or revenues;
- the targeted incentives for service quality and/or rates;
- the way the plan treats DSM;
- the way the plan explicitly coordinates the potentially different goals of multiple incentives;
- the way earnings are shared between company shareholders and customers, if this is done;
- the "Z factors", including anything labeled as a Z factor, that are referred to as such in the plan, and other features that meet our definition of the term; and
- the off-ramps that allow the company, the regulatory commission, or other parties to terminate the plan.

A.2 Alabama Power Company

The Alabama Power Company (Alabama) Rate Stabilization and Equalization (RSE) program which was implemented in 1982 is one of the oldest comprehensive incentive programs in the U.S. still in effect.

Alabama serves 1.2 million customers with 41 terawatt-hours each year. The company has annual retail revenues of $2.4 billion.[1]

A.2.1 Relationship to Competition and Restructuring

To our knowledge, the Alabama Public Service Commission is not currently taking any action concerning industry restructuring.

A.2.2 Term

There is no fixed term specified for Alabama's PBR program as a whole. The mechanism is intended to reduce the frequency of rate cases but has no minimum "stay out" provision.

A.2.3 Type

Alabama's mechanism is a form of *ROR bandwidth* regulation or *sliding-scale* regulation. Under sliding scale regulation, a target ROR or ROE is set and if the company's return strays from the target or a certain bandwidth around the target, rates are adjusted to account for the difference. The primary benefit of this type of mechanism is that it may reduce the frequency of rate cases. Because this mechanism pushes the company towards its authorized ROR, it may be a weaker form of regulation than COS/ROR with regulatory lag.

A.2.4 Scope

The RSE covers all retail nonfuel revenues. Alabama has a separate fuel adjustment clause that keeps rates in line with fuel costs (NARUC 1992).

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1 The statistics on each company's number of customers, sales, and retail revenues are drawn from EIA (1995a, Table 40).

A.2.5 Incentive Mechanisms

The RSE allows quarterly adjustment of Alabama Power's rates to reflect the difference between earned return on equity and a target return or "adjusting point," currently set at 13.75 percent. If the utility's actual return exceeds or falls short of the target by more than 75 basis points—i.e., more than 14.50 percent or less than 13.00 percent—the RSE factor is applied to existing rates, raising or lowering them to account for the deficiency or surplus in earned return. The basis-point "band" around the target is called the "equity return range."

The RSE is calculated quarterly. Return on equity for the quarterly calculation of RSE is based on the 12-month period ending with the first month of the prior calendar quarter. For example, the period used to calculate return on equity to derive RSE for the first calendar quarter (January through March) would be the 12-month period ending October 31st of the prior year.

The return on equity that is subject to the RSE adjustment is calculated as follows:

$$DROE = AROE - RRCE \tag{A-1}$$

$$if\ \ -0.75 b.p. \le DROE \le 75 b.p.,\ then\ DROE' = 0,\ and \tag{A-2}$$

$$if\ DROE > 75 b.p.,\ then\ DROE' = DROE - 75 b.p.,\ and \tag{A-3}$$

$$if\ DROE < -75 b.p.,\ then\ DROE' = DROE + 75 b.p. \tag{A-4}$$

where AROE = allowed equity target,
RRCE = actual retail return on common equity,
DROE = equity return deviation,
DROE' = deviation adjusted for deadband, and
0.75 b.p. = current value for ½ of "equity return range"

The actual rate adjustment, is made to bring Alabama's earnings into the deadband. There is also a limitation that an RSE adjustment in any period cannot change rates by more than two percentage points. The calculation of RSE is made quarterly as follows:

$$if\ (\frac{(DROE^{\prime})\times(CE)}{1-T})/RR > L\%,\ then\ RSE = \frac{(L\% \times RR)\times(\frac{BR_i}{BR_t})}{kWh_i},\ and \tag{A-5}$$

$$if\ (\frac{(DROE^{\prime})\times(CE)}{1-T})/RR \le L\%,\ then\ RSE = \frac{\frac{(DROE^{\prime})\times(CE)}{1-T}\times(\frac{BR_i}{BR_t})}{kWh_i} \tag{A-6}$$

where	CE	=	end-of-period common equity,
	T	=	federal and state income tax rate,
	RR	=	retail electric revenues for the 12-month test period,
	L%	=	percentage rate impact limit, set at 2%,
	BR_i	=	base 12-month revenues for retail rate schedule I,
	BR_t	=	total base revenues for 12-month period, and
	kWh_i	=	12-month kWh sales for rate schedule I.

A limitation not shown explicitly in the above equations above is that there cannot be two consecutive quarterly adjustments in the same direction. If a quarterly rate adjustment cannot be made because of either the percent rate impact or "same direction" limitation, Alabama can carry the adjustment forward to the next quarter. Finally, revenue increases cannot exceed four percent for any calendar year.

A.2.6 Service Quality Incentives

There are no explicit service quality incentives in this plan.

A.2.7 Rate Performance Targets

There are no explicit rate performance targets in this plan.

A.2.8 Treatment of DSM

The plan does not address DSM.

A.2.9 Coordination of Multiple Goals

There is no explicit mechanism for coordinating multiple goals.

A.2.10 Earnings Sharing Mechanism

Alabama's primary incentive mechanism *is* an earnings sharing mechanism. As noted above, within the band of ±75 basis points, Alabama's shareholders are at risk for 100 percent of any variation in the ROE. Outside this bandwidth, customers are at risk for 100 percent of any variation.

A.2.11 Z factors

If return goes outside the bandwidth, all costs effectively become pass-throughs.

A.2.12 Off Ramps

There are no explicit off ramps, but the RSE has no fixed term, so the company can file a rate case at any time.

A.2.13 Pricing Flexibility

None.

A.3 Central Maine Power Company

The Maine Public Utilities Commission (MPUC) requested Central Maine Power (CMP) and other interested parties to negotiate an Alternative Work Plan (ARP) in 1993. On October 14, 1994, CMP filed a stipulation with the MPUC detailing the consensus of MPUC staff, the Office of the Public Advocate, the Commercial Customer Utility Coalition, the U.S. Navy, the Maine State Legislative Committee, and CMP itself. On December 30, 1994, the MPUC issued a "short order" adopting the stipulation, and on January 10, 1995, the MPUC issued its final order approving the ARP. The description below is drawn from this order (MPUC 1995). Specifically, the stipulation addressed 11 issues:

1. selection of a price index
2. creation of a profit-sharing mechanism
3. selection of a productivity offset
4. scope of an annual review
5. incentive for customer satisfaction and reliability
6. definition of mandated costs
7. treatment of fuel and purchased-power costs
8. treatment of DSM
9. options for termination
10. allowances for pricing flexibility
11. provisions for electricity lifeline program (ELP)

CMP serves half a million customers with 9.4 terawatt-hours a year. The company generates annual operating revenues of $848 million.

A.3.1 Relationship to Competition and Restructuring

The Maine legislature created a surplus power auction program in 1994, they began their active involvement in utility restructuring. Since May of 1994, the MPUC has initiated two dockets related to restructuring and stranded assets. However, these were both terminated because the FERC addressed most of the MPUC's concerns, and there is no direct connection between these activities and CMP's PBR plan.

A.3.2 Term

The ARP will last five years, from 1995 through 1999, and is reviewed annually. The MPUC will also conduct a midperiod review in 1997 and an end-of-plan review in 1999.

A.3.3 Type

Central Maine Power has a price-cap mechanism as well as a variety of targeted incentives.

A.3.4 Scope

The price cap covers all retail rates and does not allow pass-throughs for fuel costs.

A.3.5 Incentive Mechanisms

Price CEP

For each of CMP's customer classes, prices are indexed annually in the following way:

$$P_t = P_{t-1} * [1 + (1-Q)(I - X) + Z],$$

where P_t = CMP's average price of electricity in year t,
Q = qualifying facility factor initially set at 37.5%,
I = the implicit price deflator for gross domestic product,
X = productivity factor, and
Z = other flow-through costs such as the cost of DSM programs and rewards and penalties for service quality.

From this equation , the annual increment to prices is given by the following:

$$(1-Q)(I - X),$$

where Q reflects the amount of CMP's costs that do not change because of fixed-price contracts. Q = 0 in 1995 and 37.5 percent in the years 1996 through 1999. Annual price changes for the five years of the plan (i.e., the price index) are given by the following:

Table A-1.

Plan Year	Price Index Change
1995	(I-0.5%)
1996	If I: ≤4.5%, then (I-1.0%)
	If I:>4.5%, then the greater of:
	1. 3.5%
	2. (1-0.375)*(I-1.0%)
1997-1999	(1-0.375)*(I-1.0)
Where 0.375 in the equations for 1996-1999 is the Q factor.	

The implicit price deflator of gross domestic product is used as the measure of inflation (I). For the beginning of any year t (t=1996 through 1999), the relevant I is the difference between the Implicit Price Deflation (IPD) in the fourth quarter of year t-1 and that of the fourth quarter of year t-2.

CMP uses an index of output prices in the general economy, as part of what is commonly known as a telecommunications-style index . General economy-wide productivity changes are implicitly included in the index. However, using the index as a measure of input cost changes in the electric power sector requires a productivity adjustment: the difference between productivity in the general economy and in the electric industry or specifically at CMP. The productivity offset for CMP includes a "stretch" factor or cost-reducing incentive. The MPUC's final order on the price-cap plan explains:

> In our Phase I order, we noted that the productivity offset is 'the most significant issue in determining the specific characteristics of an ARP, and indicated that the productivity offset should be no less than one percent. We also suggested that a "stretch factor" to the productivity offset be considered to minimize risks to consumers and to provide further incentive for CMP to improve its cost efficiency (MPUC 1995).

Targeted Incentive on QF Buy-Out or Buy-Down Costs

In the U.S., Maine has the most power generated from qualifying facilities (QFs) as a percentage of total generation. An apparent concern of the ARP sponsors is that in a more competitive market, many existing QF contracts may be above the market price of power. As a result of this concern, the price-cap plan gives CMP the incentive to restructure or buy out existing contracts with QFs. Any savings from buy-out or restructuring will be shared equally between shareholders and ratepayers, and the Z factor will be the mechanism through which savings are passed along to customers. However, if any of the restructuring or buy-outs are financed through the Finance Authority of Maine, the savings will be passed through totally to ratepayers. In any case, the savings from changes in QF contracts will affect rates in the year following the changes.

A.3.6 Service Quality Incentives

CMP's Customer Service and Reliability rewards and penalties are incorporated into the price -cap formula as Z factors (Section A.3.11). The actual incentive is based on five measures of performance:

Customer Satisfaction

1. Percentage of phone-center transaction customers who answered "yes" to a post card survey question about the whether of CMP's employees appeared knowledgeable. The survey was administered to a random sample of customers throughout the year. The baseline is 82%.

2. Percentage of new-installation customers who responded that their installation occurred on time in a survey administered to a random sample of customers throughout the year. The baseline is 72%.

Service Reliability

3. Average Duration of Interruptions. The baseline is 180 minutes.

4. Average interruptions (excluding storms). The baseline is two.

Customer Service

5. Complaint Ratio. The 1993 baseline is 1.17 complaints per 1,000 customers.

Each indicator is worth 20 points for a total of 100. Subpar performance for any of the indicators reduces the indicator on a percentage basis (i.e., the percentage shortfall times 20 points). If CMP exceeds the indicator, it receives 20 points. The penalty for performing less than the indicator is as follows:

Table A-2.

Points	Penalty
99-99.9	$0.25 million
98-98.9	$0.50 million
97-97.9	$0.75 million
96-96.9	$1.0 million
94-95.9	$1.5 million
92-93.9	$2.0 million
<92	$3.0 million

(Note: One million dollars is equivalent to 14 ROE basis points.)

A.3.7 Rate Performance Targets

None separate from the main price cap mechanism.

A.3.8 Treatment of DSM

Beginning in 1996, DSM costs will be included in the price-cap formula as a Z factor (see Section A.3.11) up to a maximum of $2 million. Amounts exceeding $2 million will be deferred and recovered in the following year. DSM-related expenditures include deferred DSM costs and reconcilable costs.

CMP will file a Least Cost Energy Resource Plan on April 1, 1995. The plan will be updated annually and approved by MPUC. As part of the plan, CMP will set annual savings targets for its DSM programs. If these targets are not achieved, CMP will incur penalties. If CMP fails to meet 90 percent of its DSM goals in two successive years, any party can petition the MPUC to terminate or modify CMP's price-cap plan.

Targeted DSM savings for 1995 are 45 GWh. For rate making, CMP must achieve at least 90 percent of that target. If the firm falls short, the following penalties apply:

Table A-3.

Savings	Reduction in Revenues
85-89%	$1.5 million
80-84%	$2.0 million
75-79%	$3.0 million
<75%	$5.0 million with 25 basis points reduction in ROE to calculate profit sharing

The reduction in revenues are for one year, and the penalties will not be considered in the calculation of earnings for profit sharing; however, as noted above, performance less than 75% will reduce earning sharing targets by 25 basis points.

CMP has an incentive to attain more than the targeted savings. If the utility exceeds the target in any year, a $1.0 million deferred credit will be created to offset any penalties in subsequent years. The credit is only for purposes of offsetting penalties.

A.3.9 Coordination of Multiple Goals

See discussion of service quality and DSM above.

A.3.10 Earnings Sharing Mechanism

A symmetrical band is placed around CMP's targeted equity earnings of 10.55 percent. Earnings in excess of 10.55 percent but less than or equal to 14.05 percent—a 350 basis point upper band—are kept entirely by CMP's shareholders. Earnings greater than 14.05 percent are shared equally by CMP's shareholders and ratepayers. Similarly, earnings 350 basis points below the 10.55 percent target are borne exclusively by CMP's shareholders. Earnings more than 350 basis points below the target are shared equally by shareholders and customers.

A.3.11 Z factors

Costs allowed for in targeted incentives for DSM, customer service, and QF buy out or buy down are amortized as Z factors. In addition, the MPUC requested that interested parties define mandated costs and come up with ways to address DSM and low-income programs. Along with some accounting adjustment costs, these items are part of the mandated costs that are included as Z factors. DSM is discussed in Section A.3.8. Customer service, which is also treated as a Z factor, is discussed in Section A.3.6. The other allowed Z factors are discussed below:

■Electric Lifeline Program (ELP). The MPUC will determine the amount of ELP's costs to be included in the annual Z factor. Any difference between actual costs and funded amounts will be deferred until the 1997 midplan review of the price-cap plan.

■ SFAS No. 106. Fifty percent of the transition costs to Statement of Financial Accounting Standards No. 106, dealing with retirement benefits other than pensions, will be a Z factor.

■ Other. In addition to these items, the MPUC has the authority to include other unforeseen mandated costs at the midyear review of the plan. Other potential mandated costs must meet three criteria: (1) exceed $3 million in annual revenue requirements; (2) have a "disproportionate" effect on CMP or the utility industry; and (3) be in adequately accounted for in the price index.

A.3.12 Off Ramps

CMP's price-cap plan has a number of reviews and proceedings built into its structure, including an annual review of CMP's performance and a midplan review in 1997.

By March 15th of each year, CMP will file the following information, which will initiate a review process that leads to price changes beginning on July 1st:

- the price index
- earnings sharing, if earnings are outside the 350 basis-point band
- Z factors (i.e., flow-through items), including customer service and reliability criteria and DSM program information
- pricing flexibility
- marginal cost estimates
- SFAS 106 costs
- load growth efforts

At CMP's midplan evaluation in 1997, the following will be specifically addressed:

■Cost of capital. CMP's cost of capital will be reviewed, which may lead to changes in the profit-sharing mechanism.

■Pricing practices. The MPUC will consider the parameters of the pricing flexibility allowed CMP.

CMP's price-cap plan can be terminated in one of two ways. First, CMP can request to terminate the plan if the utility's actual ROE falls outside the sharing mechanism band for two consecutive years. Second, any interested party's can request to terminate the plan if CMP does not achieve 90 percent of its DSM goals for two consecutive years.

A.3.13 Pricing Flexibility

CMP is allowed flexibility to price between the ceiling (the price caps are discussed in Section A.3.5) and a floor. The pricing philosophy of the agreement between the MPUC and CMP is to protect core customers and to avoid undue discrimination. CMP is allowed to develop pricing strategies outside of the agreed upon boundaries but must obtain MPUC approval before implementing them.

Under the plan, CMP may set rates without MPUC approval for three service categories: (1) existing customer classes, (2) new customer classes for optional targeted services, and (3) special rate contracts. The rates must meet certain criteria or else CMP must obtain MPUC approval, which is to take no longer than four months.

- Existing Customer Classes. CMP can set rates between the price cap and long-run marginal cost as long as LRMC is not more than 40 percent below the cap. If LRMC is more than 40 percent below, the floor is 60 percent of the price cap. In addition to rate changes in response to changes in the price cap, CMP cannot make no more than two rate changes per year. There are additional restrictions on rate design, customer notification, and customer information with respect to their place between the cap and the floor.

- New Customer Classes. CMP can define new customer classes to target, with special rates. To determine whether the utility has met its price cap for these new classes, it uses the price cap closest to the one that the new customers would fall under if they had been existing customers.

- Special Contracts with Individual Customers. CMP can enter into contracts lasting five years or less that begin in either 1995 or 1996 with a discount from the cap. Over the life of the contract, the revenue collected cannot be lower than CMP's short-run marginal cost plus 1.5 cents per kWh. CMP can also enter into long-term (> 5 years) contracts, but they must be approved by MPUC.

In the interim between CMP's filing of the stipulation and the MPUC's adoption, CMP filed revised rate schedules and the restructuring of contracts with 14 of its large industrial customers, CMP claims, who are most likely to leave or bypass CMP's system.

A.4 Consolidated Edison of New York

ConEd is a combined utility providing electricity, gas, and some steam. The company serves three million customers with about 36 terawatt-hours per year and has estimated annual retail revenues of $4.9 billion.

The company's current PBR mechanisms resulted from a settlement among most parties in ConEd's 1995 General Rate Case (GRC). The settlement grew out of a proposal made by commission staff that was originally rejected during litigation by both the company and the administrative law judge. This summary is based on the commission order approving this settlement (NYPUC 1995).

A.4.1 Relationship to Competition and Restructuring

Although the settlement that resulted in the incentive mechanism discussed below made no direct reference to competition and restructuring, the administrative law judge who heard the initial litigated positions of the parties recommended that the commission make a relatively conservative decision until the commission and the company had clearer visions of a competitive market.

A.4.2 Term

The term of the mechanism is three years. The first year is indexed, but the actual costs incurred in this year are also used to true up the index for the following two years.

A.4.3 Type

ConEd has a revenue per customer index for its base revenue. This type of index adjusts allowed revenues up or down by a given amount for each customer the company gains or loses. The commission expressed some concern that this would give the company an incentive to game the customer count by putting multiple meters where one would suffice. However, the assumption behind this approach is that the customer count is largely beyond the company's control and that indexing revenues instead of rates means the company's incentives for DSM are not hindered.

A.4.4 Scope

The revenue per customer incentive mechanism used by ConEd, only covers a restricted part of the company's revenues; however, some other revenues are covered by targeted mechanisms, including fuel cost and the allowed ROE. Costs treated as pass-throughs are Independent Power Producer (IPP) capacity costs, pension and other post-employment benefit expenses, DSM program costs (as discussed in Section A.4.8), and renewables. All are reconciled each year.

A.4.5 Incentive Mechanisms

ConEd has a revenue per customer index for its "pure base revenues" and two targeted incentives. Pure base revenues are defined in the settlement as revenues from rates and charges excluding fuel costs and revenue taxes.

The first step in calculating the allowed base revenues is to calculate revenue per customer (RPC) factors. These are done by customer class and are equal to the base revenues forecasted to be collected from a given customer service class in the first year (ending March 31, 1996) divided by the forecasted number of customers in that class. These factors for the first year are presented in Table A-4. In years two and three, the base RPCs are adjusted for certain pass-throughs as noted in Section A.4.4 above. The number of customers used to calculate the RPC factors stay fixed over the term of the PBR mechanism.

At the end of each year, the allowed revenue for that year is calculated by customer class using the following formula:

$$Allowed\ Rev_{t,SC} = Adjusted\ RPC_{t,SC} \times Actual\ no.\ of\ custs_{t,SC} \qquad \textbf{(A-7)}$$

Where:

$$Adjusted\ RPC_{t,SC} = Base RPC_{t,SC} + \left(\frac{(Base RPC_{(t-1),SC} \times Actual no.custs_{t-1,SC}) - Billed Revs_{t-1,SC}}{Actual no.of custs_{t,SC}}\right). \qquad \textbf{(A-8)}$$

As the equations show, variation from the allowed revenues resulting from changes in sales-per-customer is collected from or rebated to the customers in the following year via the computation of an *adjusted* RPC.[2]

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2 The settlement and the equation shown only allows for revenue windfalls and shortfalls to be dealt with in the following year. The commission worried about potentially large revenue shortfalls that would have to be charged to customers and reserved the right to spread the recovery over two years.

Table A-4. Calculation of RPC Factor (Year One)

	Forecasted No. Of Customers	Forecasted "Pure" Base Revenue ($000)	Base Revenue Per Customer ($/Cust) Base $RPC_{1,SC}$
Service Class (SC)	(1)	(2)	(3) = (2)/(1)
SC1	2,576,096	1,245,276	483
SC2	309,835	264,380	853
SC4	1,810	501,303	276,963
SC7	16,245	14,479	891
SC8	1,835	132,337	72,118
SC9	95,516	1,284,859	13,452
SC12	485	21,987	45,334
SC13	1	4,513	4,513,000
SC5	19	3,013	158,579
SC6	348	356	1,023
SC3	45	58	1,289
TOTAL	3,002,235	3,472,561	

Based on Table C-1 (NYPUC 1995)

Allowed Return on Equity

The benchmark allowed ROE is set for the first year at 11.10 percent. For the following two years the allowed ROE will be adjusted by one half the change in 30 year treasury bond interest rates. The change will be calculated as the difference between the subsequent year and the initial year. Therefore, in 1996 the change will be the difference between 1996 and 1995 whereas in 1997 the change will be the difference between 1997 and 1995. For the sake of calculating overall return, the company's capital structure will assumed to be fixed. For each basis point
change in the cost of capital, the next year's revenue requirement will be adjusted by $1.44 million.

Excess earnings greater than 50 ROE basis points above allowed ROE are shared with customers as discussed below in Section A.4.10. There are also targeted incentive mechanisms for DSM, customer service, and reliability discussed in Appendix A, Sections 4.8 and 4.6.

Fuel Cost Incentive

The company shares with customers any variation between its actual fuel costs forecasted targets. The sharing ratio is 30%/70%, company/customers. The company's maximum risk exposure on this incentive is capped at ±$25 million for nonnuclear fuel costs. The forecasted targets are set using a production-cost model and allow the company to keep for 18 months any savings from renegotiating IPP contracts.

A.4.6 Service Quality Incentives

Customer Service

The customer service incentives are based on two sets of indicators. One set called performance standards is used to determine any possible rewards. The other, threshold standards, is used to determine penalties. Taken together, the indicators offer the company the ability to win or lose up to 10 ROE basis points. The performance and threshold indicators, their base lines, and the maximum number of basis point at risk for each indicator are presented in Table A-5.

The percent of the reward or penalty given is based on the percent variation from the base level the company achieves and varies by criteria and by year. For example, in the first plan year the performance standard for PSC complaint rates awards 50 percent and 100 percent of the reward basis points for five and ten percent variations, respectively. By the third year, however, a five percent change in performance will only win 16 percent of the reward, and it takes a 20 percent change to win 100 percent.

Service Reliability

The service reliability incentive can result in a penalty of up to five ROE basis points. The incentive is based on a weighted average of the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI) for each of the four service districts in ConEd's territory, weighted by the number of customers. For each service district in which the weighted average falls below 110 percent of a minimum performance level set by the commission in 1991, ConEd loses 1.25 basis points.

Table A-5. Customer Service Indicators

Criteria	Base Level	Max Reward/Penalty (Basis Points)
Performance (Bonuses)		
PSC Complaint Rate (complaints to commission per 100,000 customers)	9.6	+2.5
Satisfaction—Visitors (based on satisfaction index rating on the semi-annual surveys of visitors, callers, and emergency center contacts)	84.2%	+1.25
Satisfaction—Callers	83.5%	+1.25
Satisfaction—Emergency Center	80.5%	+1.25
Default Rate on Deferred Payment Agreements	21.1%	+1.25
Routine Investigations (% of investigations completed within 30 days of report)	91.5%	+2.5
Threshold (Penalties)		
PSC Complaint Rate	9.6	-3.75
Work Orders—Initial Phase (average days to completion)	6 Days	-1.875
Work Orders—Final (average days to completion)	7.9 Days	-1.875
Calls Answered Rate (% of calls to customer service line not abandoned)	97.4%	-1.5
Meter Read on Schedule	90.2%	-2.25
Bill Accuracy	99.7%	-3.75
Service Reliability	110% of PSC standard	-5

A.4.7 Rate Performance Targets

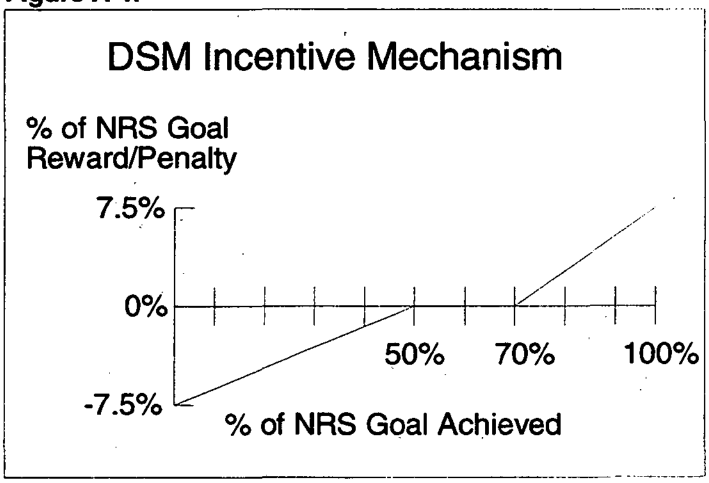
None.

A.4.8 Treatment of DSM

ConEd's DSM incentive mechanism is pegged to the net resource savings (NRS) produced by the company's DSM programs. The goal for 1995 is $135,361,000; and the goals for 1996 and 1997 will be set through the traditional IRP process. The reward or penalty available through the incentive is ±7.5% of the NRS goal. The rewards start if the company can achieve over 70 percent of the NRS goal and ramp up on a straight-line basis to 7.5 percent as the company's programs near 100 percent of the NRS goal. Similarly, penalties start to kick in below 50 percent of the goal. (See Figure A-1.)

In the event that the company spends more than the budget for a given year on DSM, the company may only defer and recover during the next year the same percentage of the allowed budget as they achieve above the NRS goal. Furthermore, the utility may not defer more than 30 percent of the budget. Therefore, if the company overran its budget by 110 percent but only overshot its NRS goal by 105%, it could only defer five percent of its budget.

Figure A-1.



A.4.9 Coordination of Multiple Goals

No explicit coordination mechanism.

A.4.10 Earnings Sharing Mechanism

If the company earns more than 50 basis points above the allowed ROE for a given year, it has to share the excess earnings up to 150 basis points 50%/50% with customers. The customers' share of this is applied to the undefined category "customer benefit," in a manner to be determined by the commission. Seventy-five percent of earnings greater than 150 basis points above the allowed ROE go to customer. Of this 75 percent, one-third goes to "customer benefit" and two-thirds to rate reduction.

A.4.11 Z factors

While there are no explicit Z factors, each year several costs are trued up which effectively passes these costs through to customers. In the first year, these costs include R&D, pension and other post-employment benefits expenses, capacity purchase expense for contracts with IPPs for the first six months of commercial operation of each unit, and 86 percent of the difference between actual and forecast property taxes. In the second and third years these costs include IPP capacity costs, pension and other post-employment benefits expenses, DSM program costs (as discussed in Section A.4.8), and renewables.

A.4.12 Off Ramps

None.

A.4.13 Pricing Flexibility

The company received no new pricing flexibility along with the PBR mechanism.

A.5 Mississippi Power Company

Mississippi Power Company (Mississippi) started operating under the "Performance Evaluation Plan-1" (PEP-1) in 1986. In 1993 if filed an alteration to this plan known as PEP-2. This more recent version of the plan is the basis for our discussion (Irvin 1993; Thompson 1993; Mississippi Power Company 1994).

Mississippi serves 180,000 customers and generates about 7.5 terawatt-hours annually; nearly three terawatt-hours are for resale. The company generates annual operating revenues of $368 million.

A.5.1 Relationship to Competition and Restructuring

We are not aware of any substantial formal activity on restructuring in Mississippi.

A.5.2 Term

No termination date is set.

A.5.3 Type

Mississippi has a sliding scale incentive mechanism with three targeted incentives. Under the sliding scale mechanism, rates are adjusted to keep the utility's ROR within a certain bandwidth around the allowed ROR. The targeted incentives give the company an opportunity to move the allowed ROR up or down based on performance.

A.5.4 Scope

The mechanism covers Mississippi's investment base, but because it does not explicitly govern rate cases or the FAC, it may not affect all possible rate changes. Mississippi has a FAC which adjusts rates for actual fuel costs (NARUC 1992).

A.5.5 Incentive Mechanisms

Mississippi's PEP-2 creates a bandwidth around its ROR using a term known as as the Performance Based Return on Investment (PROI). As long as the company's actual ROR is within the bandwidth, no adjustment to rates is made. If the actual ROR falls outside the bandwidth, rates are adjusted up or down to bring the company's return back in line. The range of no change is equal to the PROI ±50 b.p. (approximately ±100 ROE basis points based on a equity to debt ratio of 1).

The PROI is based on the rate of return (ROR) and the company's performance rating (CPR), which ranges from 0.00 to 10.00. The formula for PROI is:

$$PROI = ROR + [10\% \times (\frac{CPR}{100})] \quad \text{(A-9)}$$

The CPR is based on three service quality indices and is discussed further in the next section. Because CPR has a range of zero to 10, this formula allows Mississippi to enhance its ROR by up to 100 basis points (200 basis points ROE) as a result of improved performance.

A.5.6 Service Quality Incentives

Mississippi's CPR is based on two service quality indices and a rate performance indicator. Each is scored on a scale from 0 to 10 and then a weighted average is taken to derive the CPR. Customer price is weighted by 50 percent customer satisfaction is weighted by 25 percent, and customer service reliability is weighted by 25 percent. The results of these indicators are reported twice a year, and the CPR adjusted semi-annually.

Customer Satisfaction

This indicator is based on a semi-annual survey of customers.

Customer Service Reliability

This indicator is based on a running average of the amount of time a customer is without power during a 12-month period.

A.5.7 Rate Performance Targets

This indicator is based on a comparison of the company's average retail price with a weighted average of other electric utilities in the Southeastern Electric Exchange. The result is used to compute the CPR semi-annually.

A.5.8 Treatment of DSM

There is no explicit treatment of DSM.

A.5.9 Coordination of Multiple Goals

None explicit.

A.5.10 Earnings Sharing Mechanism

Within the approximate ±100 ROE basis point bandwidth, shareholders are at risk for 100% of any earnings variation. Outside this bandwidth, customers are at risk for 100% of any variation. The actual mechanism is defined in terms of ROR.

A.5.11 Z factors

None explicit.

A.5.12 Off Ramps

Although there is no explicit mechanism for ending the sliding-scale as a whole, no adjustments for less than $250,000 (about six ROE basis points) are allowed, and no semi-annual adjustment may exceed two percent of annual aggregate retail revenues.

A.5.13 Pricing Flexibility

None explicit.

A.6 New York State Electric and Gas Corporation

On August 31, 1993, the New York Public Service Commission (NYPSC) issued an order approving a multiyear tariff agreement between the New York State Electric and Gas Corporation (NYSEG) and three other parties. The agreement covered three years beginning on August 1, 1993 (Current Settlement Agreement). See NYDPS (1995) for a description and analysis of this agreement.

In accordance with the agreement, NYSEG filed a second-year rate request for the period beginning August 1, 1994. On August 15, 1994, the NYPSC approved NYSEG's amended request and asked the interested parties to begin reformulating a plan to cover the third year of the Current Settlement Agreement and for years beyond that. On April 19, 1995, the parties filed a "revised settlement agreement," substituting a new three-year agreement for the one that is currently in effect. This overview is based on and describes the agreement as proposed (NYPSC 1995a). On September 27, 1995 the NYPSC approved the agreement (NYPSC 1995c).

NYSEG is a combined electric and gas utility that serves 790,000 customers selling over 13 terawatt-hours. The company generates annual electric retail revenues of $1.3 billion.

A.6.1 Relationship to Competition and Restructuring

The official position of the NYPSC is to position utilities under its jurisdiction for a transition to a competitive environment. The NYPSC views NYSEG's plan as consistent with that policy objective.

A.6.2 Term

The term of the plan is three years.

A.6.3 Type

Under the new agreement, NYSEG is subject to price caps with an earnings sharing mechanism. Although its revenues and prices are subject to caps, they are not indexed as in other price-cap plans. Instead, revenues and prices are preset for each year.

A.6.4 Scope

Although the price cap covers all rates for all customer classes, flow-through or Z factors are allowed for (1) a low-income DSM program, (2) incentives for attaining certain standards of service quality, and (3) R&D expenditures in excess of amounts contained in the revised agreement. NYSEG's current fuel adjustment clause and revenue decoupling mechanism are eliminated.

A.6.5 Incentive Mechanisms

NYSEG's price cap is straightforward: the average price of electricity will increases in years 1, 2, and 3 of the agreement by 2.9 percent, 2.8 percent, and 2.7 percent, respectively. There will be no increase in prices to certain of NYSEG's industrial customers for each of the three years. The earnings sharing mechanism is discussed below.

A.6.6 Service Quality Incentives

NYSEG currently has a Service Quality Incentive Plan in effect. It will continue under the revised settlement agreement. Under the plan, NYSEG can earn or lose up to five basis points on its equity return for service reliability, and earn as many as 10 basis points or lose as many as 20 for exceeding or falling short of customer service goals.

For its service reliability goal, the basis points are assigned using a linear ranking system consisting of 24 points as presented in Table A-6.

Table A-6.

Ranking Points	Basis Points
24	5
12	2.5
0	0
-12	-2.5
-24	-5

Each of NYSEG's 12 divisions can earn or lose up to two points in this ranking.

The ranking is based on minimum acceptable ("min") and desirable ("obj") levels of reliability using national standards, as adopted by the NYPSC in July 1991. The reliability indicator is the System Average Interruption Frequency Index (SAIFI) and the duration is the Customer Average Interruption Duration Index (CAIDI). Each of NYSEG's 12 divisions can earn ranking points according to the schedule presented in Table A-7.

Table A-7.

SAIFI	CAIDI	Points
≥ min	≥ min	0
≥ min	< min	-1
≥ min	> obj	+1
< min	≥ min	-1
< min	< min	-2
< min	> obj	0
> obj	≥ min	+1
> obj	< min	0
> obj	> obj	+2

The actual minimum and objective targets are different for each division. The SAIFI minimum ranges from 0.91 to 2.75 and the objective ranges from 0.68 to 2.50. The CAIDI minimum ranges from 1.30 to 2.50 and the objective ranges from 1.01 to 2.00.

NYSEG's customer-service program, the Service Quality Incentive Mechanism, consists of eight standards or measures:

1. excellence standards program (-40 to 0)
2. PSC complaint rate (-40 to 0)
3. customer expectation study (-20 to 0)
4. overall customer satisfaction index (-25 to 25)
5. customer contact satisfaction index (-25 to 25)
6. outreach and education index (-15 to 15)
7. uncollectible index (-20 to 20)
8. improvement implementation based on customer expectation results (-15 to 15)

The combined point total of the first three measures, called threshold goals, ranges from -100 to 0. The combined point total of the next five measures, called performance goals, ranges from -100 to +100. If NYSEG attains all of its customer-service goals, its point total is +100, which translates into 10 basis points on its return on equity. If NYSEG did not attain any of its customer-service goals, its score would be -200, or a loss of 20 basis points on its return on equity.

A.6.7 Rate Performance Targets

None.

A.6.8 Treatment of DSM

There is no explicit penalty or reward for running or not running DSM programs; however, because DSM program costs are in the rate cap, NYSEG can enhance earnings if it cuts DSM expenditures. Still, NYSEG must make a good faith effort to meet its DSM goals approved by the NYPSC for the three-year period; NYSEG cannot terminate a DSM program without obtaining the NYPSC's approval. DSM savings goals are 54.44 GWh, 54.44 GWh, and 117.63 GWh on program costs of $7,573,000, $4,591,000, and $6,090,000, for years 1, 2, and 3, respectively.

NYSEG's Revenue Decoupling Mechanism (RDM) will be eliminated during the period of the settlement agreement.

A.6.9 Coordination of Multiple Goals

The only explicit off ramps are quality of service and rates, thus, there is a minimum threshold of coordination between these goals.

A.6.10 Earnings Sharing Mechanism

NYSEG's target returns on equity for the three years of the revised settlement agreement are 11.1%, 11.2%, and 11.2%. If NYSEG's earned return exceeds the target outside a band return for each of the years, the utility must share its earnings with ratepayers in the form of lower rates. Rewards and penalties from NYSEG's service quality incentive program and partial cost-sharing related to nonutility generators are excluded from the earnings to be shared with ratepayers. In the first year of the agreement, shareholders will receive all excess earnings up to 50 basis points. Earnings in excess of 50 basis points will be shared 75%/25% between ratepayers and shareholders. In years 2 and 3, shareholders will retain all excess earnings up to 100 basis points. Earnings in excess of 100 basis points will again be shared 75%/25%, ratepayers/shareholders. This is an asymmetric sharing bound. Shareholders are responsible for all earning losses.

The profits and losses of the earnings incentive and service-quality incentive plans will be combined at the end of each year. The ratepayers' share of any earnings over the three-year period of the settlement will be accumulated for disposition at the end of the settlement period on the basis of an agreement to be reached in the third year. The shareholders' portion of any earnings from the plans will not necessarily be used to increase rates. If return does not exceed the profit-sharing thresholds discussed above, NYSEG will lose the rewards of the service-quality incentive plan. If the two plans together produce returns such that some of them must be shared with ratepayers, NYSEG can either (1) reduce its unamortized DSM balances or other "regulatory assets" or (2) reduce prices in accordance with the agreement to develop new pricing strategies in years 2 and 3 of the agreement (Section A.6.13).

A.6.11 Z factors

The provisions of NYSEG's fuel adjustment clause (FAC) will be suspended during the period of the settlement agreement. The FAC's will be eliminated by rolling the total amount of projected nonindustrial, fuel-adjustment revenue from year one of the agreement into base energy charges, effective August 1, 1995. The forecasted industrial FAC revenues for the year ended July 31, 1995 will be rolled into base energy charges effective August 1, 1995.

For the three years of the settlement agreement, NYSEG must run an Affordable Energy Program that provides education, weatherization, energy packaging, and financial assistance to 2,500 low-income, residential customers. The $475,000 total cost of the program will be allocated to the rates of residential customers.

Another Z factor relates to contracts with nonutility generators. If NYSEG realizes any net savings by renegotiating or modifying its current contracts with nonutility generators, the amount will be retained for the benefit of ratepayers in a way to be determined by the parties to the agreement when the savings are realized. However, if the savings do not extend beyond a 12-month period, they will be used to reduce the book value of regulatory assets.

Finally, under the revised settlement agreement, NYSEG budgeted $11,498,000, $11,235,000, and $9,029,000 for R&D expenditures for years 1, 2, and 3 of the agreement period. The amounts are significantly less than the NYPSC's one-percent guideline. If NYSEG must increase its R&D expenditures for the three years, they will be flowed-through, dollar-for-dollar, into rates.

A.6.12 Off Ramps

The proposed agreement can be modified or suspended in the event that NYSEG cannot provide quality service or rates become unjust or unreasonable. Any party to the agreement can petition the NYPSC for relief.

A.6.13 Pricing Flexibility

In Year 1 of the Agreement, rates for various classes of services will be set using the procedures in the "Current Settlement Agreement." However, rates for years 2 and 3 are to become more "efficient," taking into consideration price elasticities of demand and competition. No definite formula has been agreed to yet.

A.7 Niagara Mohawk Power Corporation

On February 4, 1994, Niagara Mohawk Power Corporation (NMPC) filed proposed tariffs with the New York Public Service Commission (NYPSC) for calendar year 1995 and the four subsequent years, 1996 through 1999. The filing was subsequently divided into two parts, the 1995 portion, dubbed Phase I, and the 1996-1999 portion, dubbed Phase two.

On April 21, 1995, the NYPSC issued a "Short Order" for the Phase I portion of the rate case. In response, NMPC filed a Request for Rehearing and Clarification of the Commission's Order on May 22, 1995.

With respect to the price cap plan (Phase II), staff of the New York Department of Public Service (NYDPS) and intervenors filed direct testimony in regard to the NMPC proposal on August 31, 1994. NMPC filed rebuttal testimony on September 23, 1994. An Administrative Law Judge recommended a "lengthy extension" in procedural schedules for the Phase II portion of NMPC's filing on April 5, 1995. Our discussion is based on testimony by four of the key witnesses for NMPC (Ash 1994; Flaim 1994; Hemphill 1994; Lowry 1994). During the fall of 1995, NMPC filed a new proposal that supersedes the one discussed here. We keep the discussion of the original NMPC proposal because it is instructive of what electric utility PBRs can include and because NMPC's pricing flexibility proposal is unique among our sample of PBRs.

NMPC serves 1.5 million customers and has annual sales of approximately 37 gigawatt-hours (GWh). The company receive annual operating revenues of $3.3 billion in 1992.

A.7.1 Relationship to Competition and Restructuring

Although New York had not initiated an investigation of restructuring when NMPC filed its proposal, the company claimed throughout the filing that its primary motivation was to prepare for increased competition.

A.7.2 Term

The proposed term of the plan is five years. The calendar year 1995 proposal, a traditional cost-of-service filing, was to be used as the base year after the base year rates are indexed (1996-1999).

A.7.3 Type

The mechanism sets multiple price caps on the average price of electricity as well as 15 smaller "market baskets" of services.

A.7.4 Scope

The price caps cover the electricity portion of NMPC operations, including fuel costs. NMPC is a combination utility, providing both gas and electric service. The gas department is not covered by this plan.

A.7.5 Incentive Mechanisms

Price caps would be placed on 15 "baskets" of service offered by NMPC. The net effect of any price changes for the 15 baskets is also subject to an overall cap under NMPC's proposal. With the exception of one added factor, the structure of changes in price caps from year to year for each of these baskets of services is the same as that for the overall cap. The additional factor, an "A"-factor for each of the 15 baskets, allows NMPC to increase the basket caps by a maximum of one percent above the systemwide index (Figure A-2).

NMPC's proposed system wide price cap takes the following form:

$$P_t = P_{t-1} * (1 + I - X + Z)$$

where

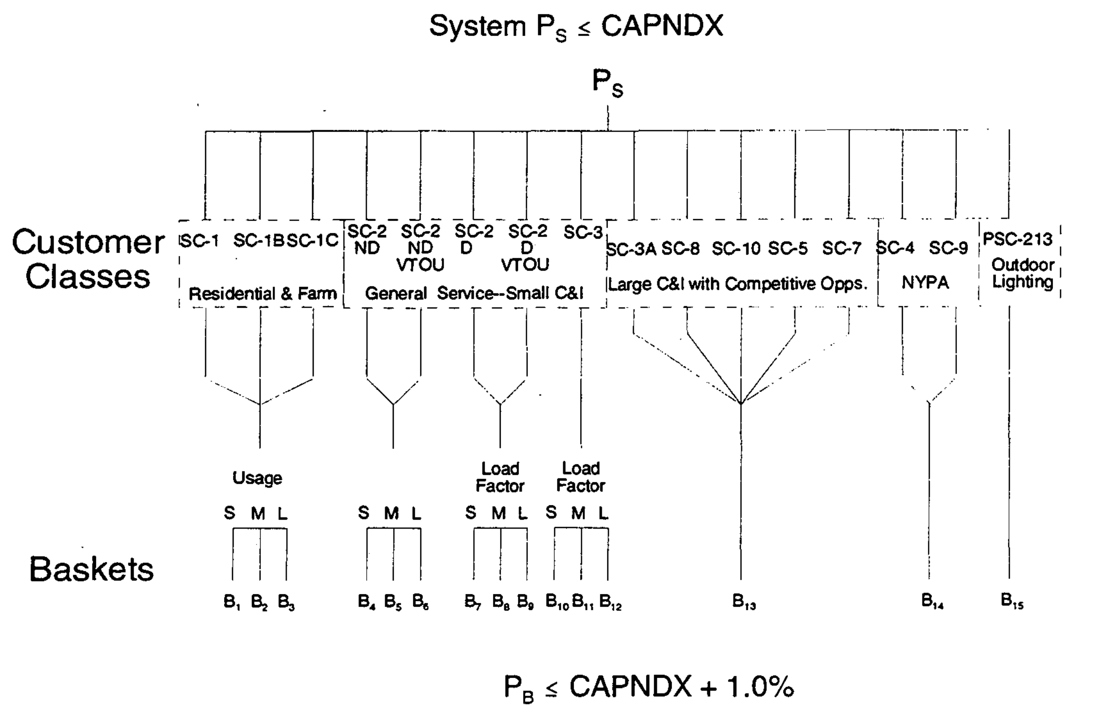
P_t = NMPC's average price of electricity in year t,

I = the consumer price index for all goods, all urban consumers,

X = productivity offset (originally set at the difference between the productivity of the entire economy and that of utilities in the northeastern United States), and

Z = other cost categories beyond the control of NMPC's management, including deferred balances on three incentive plans, certain fuel cost changes, accumulated deferrals, and changes in external business conditions.

Figure A-2.



Under NMPC's proposal, 1995 is the base year for the ensuing four years of price caps. For the price index (to be discussed below), then, 1995=100. During 1995, prices are adjusted from January 1 to December 31 only to account for Z factors (to be discussed below). In the proposed tariffs for 1995, there was some proposed realignment of costs, switching some revenues from noncore to core customers, reflecting cross-subsidies in prior periods. ("Noncore" customers are those classified in baskets B_{13} and B_{14} ; all other baskets are considered "core.")

From the beginning of the price-cap period, the cap for all 16 prices (i.e., the total system average price and the 15 basket prices will be increased quarterly). The increase will be based on the forecasted change in the consumer price index for each quarter. There will be no "true-ups." The quarterly forecasts will be the consensus forecast in *Blue Chip Economic Indicators*. The price changes between two quarters are weighted by the quantity of electricity consumed in the earlier period (Q_{t-1}), using a floating weight index known as a Laspeyre's index. For each of the 16 indices, the change in the index (L) for basket n is given by:

$$L = \frac{P_{n,t} * Q_{n,t-1}}{P_{n,t-1} * Q_{n,t-1}}.$$

The floating nature of the index can be seen in that the most recently available quantities (Q_{t-1}) are used each time the index, L, is updated. Of course, actual price changes by NMPC's management do not have to match the quarterly increases in caps. The caps are the ceilings; price increases may instead be determined by market conditions, and no floors are specified. NMPC must give a 30-day notification before increasing actual prices charged.

Inflation and Productivity

In NMPC's application, the inflation index net of productivity changes in the general economy and the electric power sector is called "CAPNDX." NMPC proposes an index of output prices in the general economy. Because such an index is commonly used in telecommunications, it is known as a "telecommunications-style" index. General economy-wide productivity changes are implicitly included in the index. However, to use the index properly as a measure of input cost changes in the electric power sector, we must make an adjustment: the difference between productivity in the general economy and productivity in the electric industry or for NMPC. The price or inflation index proposed by NMPC is the consumer price index for all goods and all urban consumers (CPI-U) calculated and published by the Bureau of Economic Analysis of the Department of Commerce.

The proposed annual productivity offset is 0.2 for all periods from 1996 through 1999. The offset is based on the difference between the estimated productivity for the entire U.S. economy and 26 electric utilities in the northeast for the latest 10-year period for which data were available when the offset was estimated (1980-1990). The U.S. economy's productivity is the average rate of change in the Bureau of Labor Statistics multifactor productivity index of the U.S. private business sector. The productivity factor for electric utilities was estimated by NMPC using data for 26 of the 28 largest investor-owned utilities in the northeast for 1980 to 1990. (Long Island Lighting and NMPC were the two utilities excluded from the estimation.) The 0.2 productivity offset is the difference between the average rate of change in productivity of the U.S. economy from 1980-1990 (0.87%) and that of the 26 utilities in the northeast (1.10%).

A.7.6 Service Quality Incentives

NMPC also proposes a customer service plan to motivate itself to maintain and improve service quality under the price-cap plan.

For residential customers, an "internal index" is based on the results of a quarterly random mail survey of residential customers who have had service transactions with company in the previous month. The "external index" for residential customers is based on NMPC's performance against a peer group of 23 northeastern utilities. The performance is based on a national study of 40,000 customers. In 1993, NMPC had 7.1 complaints per 100,000 customers per month, ranking sixth among nine New York State (NYS) electric and gas utilities. NMPC proposes to improve performance to rank in the top half for the period 1996-1999. The index for small, medium, and large commercial and industrial customers is based on an annual telephone survey. The last two service quality measures are indices for outage frequency (SIF) and outage duration (CID). The seven targets are shown in Table A-8.

Table A-8. Service Quality Performance Standards

		Target Values			
	Base	1996	1997	1998	1999
I. Residential Customer Satisfaction					
Internal Index	80.8	84.0	85.0	85.0	85.0
External Index	-2.3	-0.5	+0.5	+1.5	+2.5
PSC Complaints	6th of 9	Top half of New York State electric and gas utilities			
II. Commercial-Industrial Customer Satisfaction					
Small and Medium	71.9	74.9	75.9	76.9	77.9
Large	76.6	79.6	80.6	80.6	80.6
III. Reliability					
SIF	0.95	0.95	0.95	0.95	0.95
CID	1.70	1.65	1.65	1.65	1.65

Based on direct testimony of Joseph Ash (Ash 1994).

NMPC can lose as much as $6 million annually if it fails to meet three or more of seven targets as shown in Table A-9.

Table A-9.

Missed Targets	Penalty
0-2	$0 million
3	$2 million
4	$4 million
5-7	$6 million

A.7.7 Rate Performance Targets

There are no rate performance targets separate from the primary price cap.

A.7.8 Treatment of DSM

NMPC will end Niagara-Mohawk Electric Revenue Adjustment Mechanism (NERAM), its current revenue decoupling mechanism. The disposition of remaining NERAM balances for accumulated deferrals is discussed below. NMPC's new philosophy on DSM programs is that "... participants should bear the full cost of DSM measures since they realize the direct economic benefits." Given this philosophy, NMPC will treat DSM as a customer service strategy, engaging in marketing efforts to address classical economic barriers to DSM such as providing information and capital access, and addressing business risk through conventional channels other than rebates.

Through NMPC's definition of Z factors, NMPC proposes to create the DSM Incentive and Revenue Adjustment Mechanism (DIRAM) to recover shareholder earnings incentive and lost revenues for its DSM activities beyond those not covered in its base rates. It will forecast lost revenues for each of its 15 baskets of services and recover the revenue and incentive annually through its current incentive, the Merit Equity Return Incentive Term (MERIT). MERIT will end in 1996. For a description and analysis of the MERIT program, see Christensen and Lowry (1992) and NYDPS (1995). That program allows NMPC to earn five percent of net reduction in company's cost for DSM plus an environmental benefit adder. Merit was capped at $5 million net of taxes, and is not effective until company achieves at least $2 million in potential awards. DIRAM differs from NMPC's old decoupling mechanism, NERAM, in that it only adjusts for lost revenues and incentives directly related to DSM.

A.7.9 Coordination of Multiple Goals

There is no explicit mechanism.

A.7.10 Earnings Sharing Mechanism

A "collar" is placed on NMPC's return on equity. In contrast to the "bands" placed around earnings in other price-cap proposals, the collar is not a mechanism for NMPC to share gains and losses directly with customers. Rather, on the downside of the proposed collar (a return 300 basis points less than NMPC's target return on equity of 11%), NMPC has the option of calling for a rate case to end price-cap regulation. The "proceeds" of any earnings on the upside of the target return are to be placed in a deferred credit account to be used to write down the total "regulatory assets" in NMPC's financial accounts. NYDPS (1995) defines regulatory assets to include uneconomic generation costs.

Also, there is no indexing of the benchmark return on equity or ROR.

A.7.11 Z factors

NMPC proposes to use three categories of expenditures as Z factors: (1) the targeted incentives discussed above; (2) accumulated deferrals; and (3) external business conditions.

Accumulated Deferrals

NMPC proposes to separate accumulated deferrals from base rates in 1995 as a separate item and treat them as Z factors to establish "appropriate" base-year rates. End-of-year balances for NERAM and the fuel adjustment clause (FAC) are all part of the deferrals to be recovered in Z factors.

External Business Conditions

CAPNDX allows price ceilings to rise because inflation is out of management's control. Along the same lines, NMPC proposes to include as Z factors other variables that are out of management's control:

- environmental and nuclear decommissioning costs
- legislative, regulatory, tax-law, and accounting rule changes that materially affect NMPC's cost structure
- energy costs changes described further below

Fuel Cost Adjustments

An energy cost adjustment mechanism is proposed to replace NMPC's fuel adjustment clause (FAC). Under the new mechanism, known as the Energy Cost Adjustment Mechanism (ECAM), NMPC proposes a mechanism for sharing—up to a point—between customers and shareholders for the difference between indexed energy costs for retail customers and the energy costs paid by retail customers. NMPC would implement this sharing through a Z-factor adjustment.

The reason for this Z factor is that the consumer price index used to reflect changes in the quarterly caps may not respond quickly to changes in external energy markets. Because energy costs are such a large portion of NMPC's total costs, they are singled out for special consideration.

The indexed net energy revenue (NER), is in reality a subindex of fuel costs for NMPC's total index. Forecasted unit energy costs for retail customers are changed annually based on CAPNDX, the same index used to cap the 15 baskets and total prices. The net energy costs (NEC), are the energy costs paid by retail customers. They are the total cost of energy less revenues from wholesale sales.

The values of NER and NEC are compared annually. Differences between NER and NEC of up to $50 million are split 60%/40% between customers and shareholders. Any difference greater than $50 million is paid totally by customers through Z factors. In other words, NMPC is only liable for $20 million (40% × $50 million) or 69 ROE basis points of fuel cost deviations.

A.7.12 Off Ramps

As noted in Section A.7.10, if earnings are less than the predefined floor (eight percent) for 12 consecutive historical months or the forecasted 12 months, NMPC can offset the deficiency with any deferred credits earned in prior periods and placed in a special account, or the utility can call for a rate case. Deferred credits include above-collar earnings from a previous year. The rate case is at NMPC's discretion and effectively ends the price-cap plan. NMPC can also file for a rate case if its first mortgage bonds are rated below "BBB" by Standard and Poors or "Ba3" by Moodys.

A.7.13 Pricing Flexibility

Pricing flexibility is addressed in three ways. First, as already noted in Section A.7.5, NMPC groups its 16 individual tariffs into 15 market "baskets," as illustrated in Figure A-2, and prices in a basket can go to 101% of the system wide cap. Second, within each basket, considerable pricing flexibility is allowed; NMPC may change rate design as well as rate levels. Third, NMPC proposes to offer alternative tariffs to most of its customers. These flexible tariffs target customers who have other energy alternatives for at least a portion of their energy requirements such as residential customers currently heating their homes with electricity.

The following describes the basket definitions in more detail. The tariffs, defined at the top of Figure A-2 as SC-1, SC-1B, etc., are grouped into 15 "baskets" (B_1-B_{15}), shown toward the bottom of the figure. Baskets are defined as both sub- and supersets of existing customer classes, and each of the 15 baskets has its own price cap. Baskets 1 through 12 reflect NMPC's residential and general service tariffs. Customers were grouped into baskets based on the most representative information (i.e., usage and load factor) about their electricity-consuming habits and, therefore, their relative costs. The three SC-1 tariffs, for example, are for NMPC's residential and farm customers. They are best grouped by kWh-consumption. The same is true for the SC2-ND tariff for small, general-service, non-demand (ND) customers using less than 2,000 kWh per month.

The SC2-D tariffs, in contrast are based on noncoincident demand. They reflect small, general-service customers using up to 100 kW/month and they are assigned to baskets based on load factor. The SC-3 tariffs are for NMPC's large general-service customers, using over 100 kW/month. They are also assigned to a basket based on load factor. With one exception, the four groups of tariffs classified by usage and load factor are further subdivided into three baskets each based on ranking of usage and load factor. The SC-3 tariff is divided into baskets B_{10}, B_{11}, and B_{12}. B_{10} contains 1,083 customers refined as "small;" B_{11} contains 1,707 medium-size customers, and B_{12} has 1,080 large customers. These baskets contain 25, 50, and 25 percent respectively of all customers under this tariff. This division results in cutoffs of $\leq$40, 40-60, and $\geq$60 percent load factor, respectively.

Tariffs SC-3A, SC-8, SC-10, SC-5, and SC-7 were grouped into one basket, B_{13}, because these customers are most likely to have opportunities to acquire power at competitive rates from sources other than the utility in the future. NMPC's SC-3A customers are large, general-service ones whose maximum demand is more than 2,000 kW/month. The SC-8 customers are also large, general service customers under NMPC's real-time rate.

Tariffs SC-4 and SC-9 are grouped together in basket B_{14} because they receive power allocations from the New York Power Authority and merely use NMPC's power as a supplement. Finally, all customers under NMPC's PSC-13 tariff are grouped together because they all require electricity for outdoor lighting.

The break points for all customer classifications are based on a single year and will not be updated for migrations across classes during the 1996-1999 price-cap period.

If actual prices are not changed to meet the price cap during a calendar year, the caps are not carried over from one year to the next for core customers. For example, if the price cap for a given year t and basket B computed by the equation above allowed an increase of five percent, and NMPC does not increase prices, the utility forfeits the right to that annual cap increase. There are no cumulation restrictions on the caps for noncore customers; caps can be carried over from year to year. Price changes shown in Figure A-2 cannot exceed the cumulated value of the caps.

Finally, at the end of each year, the capped prices are compared with actual average prices charged for the total and each of the 15 baskets. If the actual prices exceeds the cap for any of these 16 categories, rates are immediately adjusted downward in the first quarter of the following year for the amount of the increment, and for interest charges on the increment.

A.8 PacifiCorp

PacifiCorp serves seven Western states including only about 40,400 California customer. In California, the utility has annual sales of 758,029 MWh, which provide only 3% of the company's revenues. The firm's current price cap mechanism was filed Dec. 2, 1992 for 1994-96 and is the basis for this summary (CPUC 1993a).

A.8.1 Relationship to Competition and Restructuring

The plan was adopted independent of the CPUC's ongoing investigation of restructuring.

A.8.2 Term

The term is three years (1994-96). This is the same as the company's old three-year general rate cycle although the plan gives the company the prerogative to extend the plan through 1999. There is no special escape clause should the index prove unrealistic. On the other hand, there is no special prohibition against the company filing in the interim.

A.8.3 Type

This plan uses price cap incentive mechanisms, which increase or decrease the percent allowed annual percentage rate increase.

A.8.4 Scope

The price cap covers all California retail rates, including both customer charges and per-kWh charges. There is a surcharge for a low-income program, but there is no allowance for any pass-throughs such as fuel adjustment clauses. Although this is a fairly broad, powerful incentive mechanism on a per-unit basis, the size of California's service territory makes it a low-risk mechanism for the utility.

A.8.5 Incentive Mechanisms

The mechanism follows the form RPI - X + Z. In this case the company's prices are indexed to a weighted average of four price indices published by Data Resources Inc. (DRI)/McGraw Hill. The weights were derived from the company's cost structure. The four indices and their weights are presented in Table A-10.

Table A-10.

Index	Weight
Capital	49.05%
Fuel	19.86%
Materials	18.36%
Labor	12.73%
Total	100%

At the time the plan was filed, cost index increases were estimated as 4.2%, 3.2%, and 2.7% for 1994, 1995, and 1996 respectively. The X offset in this case represents a productivity factor and is based on CPUC staff's total factor productivity methodology. The x-offset was estimated to be about 1.4%, resulting in estimated net allowable increases of 2.8%, 1.8% and 1.3% which would go into effect at the end of each year. For each year of the plan, the company must file an advice letter by October 15 for an increase to be effective by January 1 of the following year.

Index Boundaries and Limitations

The price cap mechanism is limited overall; if the company's rates go above 105% of the national average of rates, no increase is allowed.

The company also voluntarily agreed to limit its first year rate increase (i.e. the increase that went into effect January 1, 1995) to 2.0% when the plan was implemented. The plan stipulated that a 2% increase would go into effect with the plan on January 1, 1994.

Low-Income Surcharge

A 0.084 cents/kWh surcharge was included in the plan to pay for the Low-Income Ratepayers Assistance plan.

A.8.6 Service Quality Incentives

There are no service quality incentives in this plan.

A.8.7 Rate Performance Targets

There are no rate performance targets in this plan.

A.8.8 Treatment of DSM

There is no special incentive mechanism for DSM. When the plan was implemented, the company agreed to certain spending and savings targets, but the existing incentive mechanism and revenue balancing account were eliminated. The plan also included a phased-in shift in DSM accounting practices in which all DSM costs would eventually be expensed. To cover this cost, rates in 1995 and 1996 will be 1.0% higher than the price index-based adjustment would allow.

A.8.9 Coordination of Multiple Goals

No explicit mechanisms. See Section A.8.8 for discussion of the company's agreements on DSM spending.

A.8.10 Earnings Sharing Mechanism

There is no earnings sharing mechanism in this plan.

A.8.11 Z factors

The Z factor in this case allows for adjustments in state or federal income tax rates and enactment of an energy related tax.[3]

A.8.12 Off Ramps

There are no off ramps in this plan.

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[3] Although the plan did not make specific reference to a Z factor, it allowed for changes based on these exogenous factors; thus, the Z concept typology is useful.

A.8.13 Pricing Flexibility

Overall, flexibility is limited to changes in an average rate below the price cap. Realigning rates between or within customer classes is not allowed. At the end of the first year, the index would have allowed the company a 3% rate increase. The company opted to only increase rate is by only 1.5%.

Allocation among classes

The plan allocated the initial 2% rate increase among different customer classes, primarily following marginal cost estimates, which is normal practice in California. The plan stipulated that future rate increases would be allocated in proportion to this initial increase.

Allocation within classes

Similarly, to the allocation among classes, the method for allocating rate changes to different prices within a class are set forth in the plan. Most changes in rates would result in changes in energy charges.

A.9 Pacific Gas and Electric

PG&E is the largest utility in the country. It provides both gas and electricity, serves 4.3 million customers with 71 terawatt-hours of electricity, and generated $7.5 billion in retail revenues in 1993.

The company's PBR proposal, filed in March of 1994, it is currently on hold. This summary is based on the company's proposal (PG&E 1994).

A.9.1 Relationship to Competition and Restructuring

PG&E filed its proposal on March 1, 1993. Later the California Public Utilities Commission (CPUC) initiated its investigation into restructuring the electric industry (I/R 94-04-031). As of July 1995, PG&E's filing is still on hold.

A.9.2 Term

The term of PG&E's plan is five years. The plan actually has no explicit ending point, but the company recommends that the CPUC review the plan after five years. The company initially proposed that the plan take effect in 1995 with the 1995 GRC setting the initial values for the mechanisms. The first review would then be in 2000.

A.9.3 Type

The plan uses a base-rate revenue index. As opposed to a price or revenue cap, which sets an upper limit of rates or revenues, a revenue index takes an initial amount of allowed revenue and adjusts it each year according to an external index.

A.9.4 Scope

The incentive does not cover fuel and purchased power directly, but the company has said that it plans to offer targeted incentives to cover these. Electric Revenue Adjustment Mechanism and the Energy Cost Adjustment Clause (ECAC) would remain in place.

A.9.5 Incentive Mechanisms

PG&E's base-rate revenue index mechanism adjusts that company's allowed revenues which, in turn, are used with forecasts of sales to set rates. The index includes inflation, productivity, and customer growth. The formula for indexed base revenue is as follows:

$$IBR_t = IBR_{t-1} * (1 + I - X + \%CG) \pm SEA$$

where:

IBR_t	=	Index base revenues for a given year,
I	=	Recorded inflation as measured by the Consumer Price Index for urban areas for the 12 months ending June 30 of year t-1,
X	=	Prescribed productivity offset of 1.2%,
$\%CG$	=	Average annual change in recorded customer growth for the 12 months ending June 30 of year t-1, and
SEA	=	Amount of shared earnings and other adjustments, if any, that have to be rebated or collected from customers (see Section A.9.10).

PG&E also proposed an indexed price cap for its large electric manufacturing class (LEMC). The formula is as follows:

$$P_t = P_{t-1} * (1 + I_{LEMC} - X_{LEMC} \pm Z_{LEMC})$$

where:

P_t	=	The price cap for LEMC for a given year,
I_{LEMC}	=	Inflation index for LEMC—the Producer Price Index for Industrial Electric Power— in the appropriate period,
X_{LEMC}	=	0.5% Productivity factor for LEMC, and
Z_{LEMC}	=	Adjustments for LEMC.

Although 0.5% seems like a particularly low productivity offset, the company claims that since the PPI-IP is an electricity output index, it captures the industrial power average total factor productivity growth rate, so this X factor is actually very aggressive.

The company also proposes three new performance standard incentives. Two of these address service quality—customer satisfaction and electric reliability—and the third addresses energy bills. These are discussed in Appendix A, Sections 9.6 and 9.7 below. The total reward or penalty possible from these performance incentives is $57 million. These incentives would first be calculated in 1996 based on 1995 results, and the reward or penalty would affect 1997 authorized revenues.

A.9.6 Service Quality Incentives

The service quality incentives are based on measures of customer satisfaction and electric reliability. Customer service determined by a mail survey of customers who have had a service transaction with the company recently. One question in the survey asks customers to rate the company's service overall, with four possible answers. The company's reward or penalty would be based on the change in average score from year to year. This measure covers both gas and electric service and has a maximum reward or penalty of $25 million which would be divided: $19 million for the electricity department and $6 million for the department of the utility.

Electrical service reliability would be measured by three indicators: the total number of sustained and momentary outages; the total number of customers affected by sustained and momentary outages; and the average number of customer minutes taken to restore service in a sustained outage. The averages of these indicators from a five-year reference period would be used to create a reference score. The maximum reward or penalty would be $19 million.

A.9.7 Rate Performance Targets

The company proposed an energy bill performance standard, which would be based on a comparison of the company's overall residential electric and gas bills to the national average. The reward or penalty would be decided by comparing this ratio against the prior five years' moving average ratios. The maximum reward or penalty will be $19 million for electric and $6 million for gas.

A.9.8 Treatment of DSM

DSM will continue to be addressed through the Customer Energy Efficiency shareholder incentive. This incentive is set in another proceeding and collected from all customer classes according to designated proportions. The company would collect these incentives in every year of the PBR mechanism, including 1995.

A.9.9 Coordination of Multiple Goals

There is no mechanism for coordinating multiple goals. The company did, however, explicitly choose a revenue index and a bill performance incentive so as not to create conflicts with the DSM incentive.

A.9.10 Earnings Sharing Mechanism

The company proposed an earnings sharing mechanism with a target ROE benchmark pegged to the 30-year treasury bond rate. The actual benchmark is the bond rate + 465 basis points. If earnings are within ±200 basis points of this target, shareholders keep or pay 100% of the difference. Beyond a 200-basis point band, shareholders and customers share 50%/50%.

A.9.11 Z factors

PG&E proposed two categories of Z factors. The first would cover events currently covered by the Catastrophic Event Memorandum Account. To qualify events would have to be declared disasters by federal or state officials. The second category includes any extraordinary cost over $50 million. Only for events that meet this threshold would the company have the option of requesting the CPUC's permission to adjust its base revenues.

A.9.12 Off Ramps

In the event that the company's earnings vary by more than ±500 basis points from the benchmark ROE discussed in Section A.9.10 an optional review of the PBR mechanisms could be initiated by either the company or the CPUC.

A.9.13 Pricing Flexibility

Under its price cap for the Large Electric Manufacturing Class (LEMC), PG&E proposed significant pricing flexibility. The flexibility includes being able to offer a variety of tariffs, short- and long-term contract options, and a range of firm and nonfirm service alternatives. The company would be at risk for any revenue shortfall from these tariffs.

A.10 Southern California Edison

Southern California Edison (SCE) is an electric utility. In 1993, the company had 4.12 million customers, sold 70 terawatt-hours, and had retail revenues of $7.1 billion.

This appendix focuses on both a revised transmission and distribution PBR plan that SCE filed in August 1994 and a generation PBR plan it proposed in July 1995. As of July 1995, the CPUC had not issued a decision on SCE's proposal on transmission and distribution PBR. We summarize the company's proposals and discuss alternatives to the T&D PBR plans proposed by staff and intervenors (Section A.10.14). SCE's generation PBR plan, the Fossil Generation Transition Mechanism, is discussed in Section A.10.5.

This summary is based on the company's 1994 proposal (SCE 1994a; SCE 1994b; SCE 1994c) and on its July 1995 additional proposal (SCE 1995).

A.10.1 Relationship to Competition and Restructuring

In December, 1993, SCE filed a proposal for a base rate PBR mechanism. In July of 1994, the California Public Utilities Commission (CPUC), in light of its April decision to investigate restructuring the electric industry (I/R 94-04-031), ordered SCE to refile its proposal divided into two parts. The first "phase" required the company to change its base rate PBR into a transmission and distribution PBR plan. The second phase, which was optional, would deal with generation. The commission also asked that whatever incentive mechanism was finally proposed be flexible enough to deal with possible changes in industry structure (CPUC 1994a).

As part of the Phase I filing, the commission stated that the company should explain in detail how it would allocate costs between generation on the one hand and transmission and distribution on the other (CPUC 1994a). In SCE's Phase I filing, however, the company was careful to point out that the allocation it proposed for the PBR mechanism would not be an appropriate allocation for the purposes of direct access. In particular, the company stated that the classification of a cost as generation for the purposes of the PBR plan did not necessarily mean that cost was fully avoidable and therefore some of these costs may eventually be reallocated to T&D rates as a transmission charge. In May 1995, the CPUC issued a policy proposal wherein it favors the creation of an independently operated pool for all California IOUs. Presumably, any generation PBR plan adopted in California would need to reconcile the operation of the pool with each utility's method of ratemaking for retail customers. SCE, in its July 1995 comments on the CPUC policy proposal, provided a detailed description of its generation PBR plan.

A.10.2 Term

The term of SCE's plan is six years. In the proposal, base values would be set in the 1995 Test Year General Rate Case. The next full review of these values would not be until 2001. SCE's generation PBR plan would have a term of eight years.

A.10.3 Type

The transmission and distribution PBR plan uses a base revenue index with revenue sharing, accompanied by several targeted incentives. For its generation PBR plan, SCE proposes a hybrid revenue price cap mechanism. The mechanism is defined mechanically as a revenue cap, consisting of a fixed baseload payment and a payment that is a function of output. In terms of marginal incentive properties, the generation PBR plan is similar to a price cap.

A.10.4 Scope

The proposed base-rate revenue mechanism includes all nongeneration costs and the allowed ROE. Thus the mechanism is fairly broad based. Specific Z factors are addressed below in Section A.10.11. The mechanism excludes nuclear decommissioning costs and costs related to low-emissions vehicles and only includes DSM and R&D in a modified manner, addressed below in Section A.10.8.

The targeted incentives address service quality—as measured by customer satisfaction and service reliability indexes—and rate and bill performance.

The proposed generation PBR plan addresses all fossil generation. Excluded from the generation PBR plan are nuclear generation and non-market-responsive portions of purchased power contracts, including purchases from Qualifiying Facilities (QFs)

A.10.5 Incentive Mechanisms

Transmission and Distribution

SCE's proposed base revenue indexing mechanism looks in part very much like an archetypal indexing mechanism (i.e. CPI - X + Z). There is, however, a second term, which adjusts for customer growth. The full equation for the nongeneration indexed base rate revenue (NIBRR) for any test year, t, is:

$$\begin{aligned} NIBRR_t \quad = \quad & NIBRR_{(t-1)} * (1 + \Delta CPI - 1.4\%) \\ & + CGA_{(t-1)} * \Delta customers_{(t-1)} * (1 + \Delta CPI - 1.4\%) \end{aligned}$$

where:

ΔCPI	=	the annual Consumer Price Index for all urban consumers,
1.4%	=	the annual nongeneration "productivity pledge" and
CGA	=	a "customer growth allowance" of $773 for each new customer.

The "Productivity Pledge". The company based its "productivity pledge" of 1.4 percent per year on estimates of its own total factor productivity (TFP) from 1986-1992 for nongeneration factors (0.9%-1.0%), estimates of TFP for company wide factors from 1977-1993 (1.0%-1.3%), and estimates of other companies' TFP (0.4%-.07%).

Customer Growth Allowance (CGA). The CGA value of $773 is based on the company's 1994 authorized cost of capital (9.17%) and would need to be adjusted for the 1995 authorization. This value is the company's estimate of the marginal cost of serving additional customers.

Cost of Capital Trigger Mechanism. The Trigger Mechanism automatically adjusts the company's allowed return on common equity from a base level set in the 1995 GRC. This adjustment would take the place of the annual cost-of-capital proceeding. The ROE would be indexed to one-half of changes in the annual average of the double-A utility bond rate that are greater than 100 basis points. If annual average is greater than 100 basis points, which trigger a change in the ROE, the comparison point for bond rate changes would also be reset.

For example, suppose the 1995 GRC the bond rate, set in 1994, is 7.5%. If, in 1995 the actual average is 9.0%, a change that is larger than the 100 basis point trigger, the ROE would be adjusted upwards by 75 basis points (one-half of 150 basis points), and the comparison point for bond rate changes would be set at 9.0%. If in the following year the annual average double-A bond rate fell to 8.5%, neither the ROE or the comparison point would be changed.

Performance Incentives

The performance incentives are targeted at two areas: service quality, and bills and rates. Service quality is addressed because of fears that the base rate revenue index will push the company to skimp on service. This incentive is based on two measures, each of which, if triggered, can result in penalties only. The total potential penalty is $10 million, $5 million for each measure.

The first indicator is customer satisfaction, and measured through customer surveys. The benchmark for this indicator is the number of customers responding in the top two categories—"completely satisfied" and "delighted"—out of six. The benchmark is set at 65% with a deadband of 3%. From 61 to 57%, the $5 million penalty is scaled in at $1 million per percentage point.

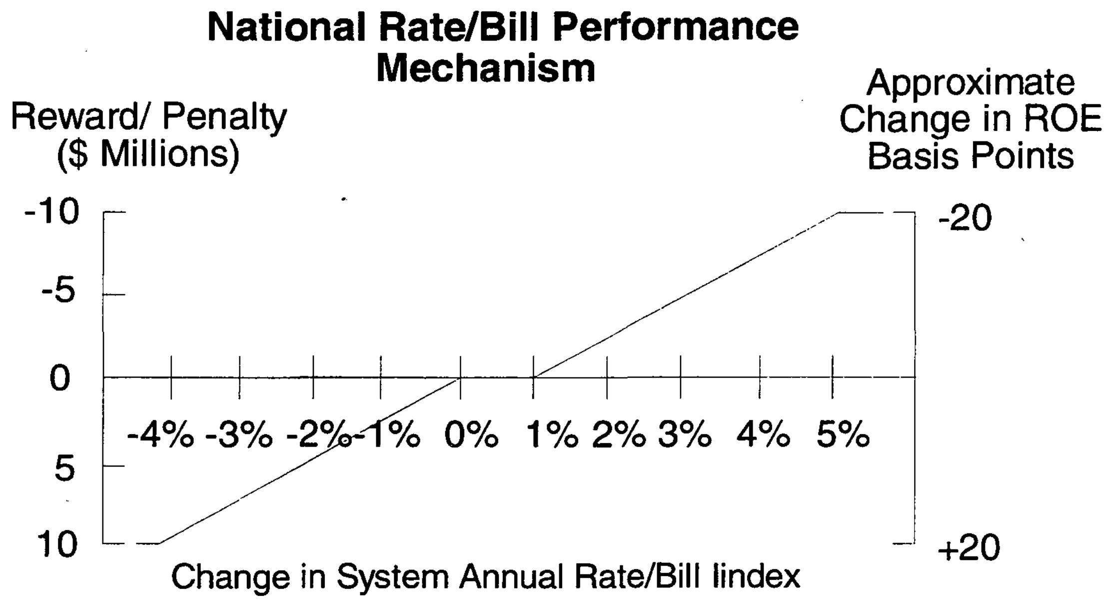
The second indicator of service quality is service reliability, measured by the average customer minutes of interruption (ACMI). From 1984-1993, the company averaged 44 minutes/year of nonstorm ACMI, excluding catistrophic events. In order to account for random events, a two-year rolling average is used with a five minute deadband. Thus, from 50 minutes to 54 minutes, the $5 million penalty would be scaled in at $1 million per minute.

The other of the two targeted incentives is based on a comparison of the company's average rates and bills with national averages. The purpose of including the bill comparison is to mitigate anti-DSM incentives created by a pure rate comparison. The system average rate/bill (SARB) index is based on the system average rates (SAR) and system average bills (SAB). The formula for any given year is:

$$SARB = 0.5*\left(\frac{SAR\ (Edison)}{SAR\ (National)} + \frac{SAB\ (Edison)}{SAB\ (National)}\right) . \qquad \textbf{(A-10)}$$

A reward or penalty of up to $10 million would based on the absolute change in this index from one year to the next. Because both the SAR and SAB are percentages, the change over time is a percentage too. Figure A-3 shows how the incentive level would be decided.

Figure A-3.



Based on Figure X-1. (SCE 1994b)

Fossil Generation Transition Mechanism

In July 1995, SCE filed its proposal for a generation PBR plan. Although it is not yet a formal application, we describe SCE's mechanism because it is a a novel way to handle generation PBR plan for a utility that may operate under an inpdendent wholesale pool ("Poolco") as proposed by SCE and supported by the CPUC. SCE's proposal is called a "transition" mechanism because it would be limited to an eight-year period: 1997-2004. After that, SCE would receive market prices for its generation, and generation price regulation would be eliminated.

SCE's generation PBR plan focuses on the allowed revenue recovery of its fossil fuel (coal and natural gas) fired plants. Under its proposed generation PBR plan, revenues for its fossil fuel plants would be capped according to the following formula:

$$GIRR \leq GFC + (HR(kWh) \times P_G + ER(kWh) \times P_E + VOM) \times kWh \qquad \textbf{(A-11)}$$

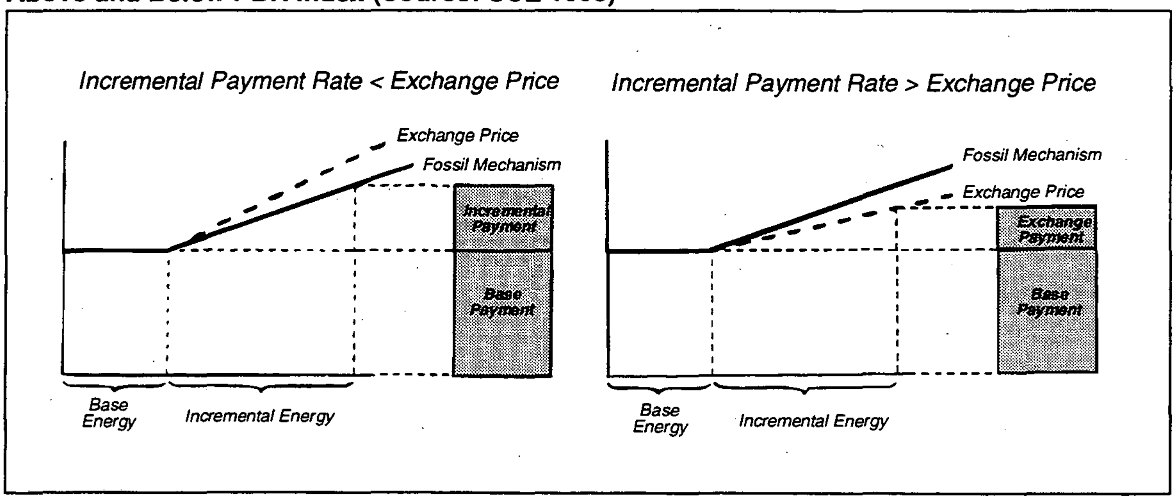
where:

GIRR	=	fossil fuel generation indexed revenue requirement,
GFC	=	generation base payment (includes depreciation, return, taxes, fixed O&M, fixed components of fuel costs, and emission trading fixed credit, subject to annual productivity factor),
HR(kWh)	=	heat rate (Btu/kWh) as a function of output,
P_G	=	indexed gas price,
ER(kWh)	=	emission rate (tons/kWh) as a function of output,
P_E	=	price for emissions ($/ton),
VOM	=	variable operations and maintenance expense adder, and
kWh	=	retail generation above 10 billion kWh/year.

Under the Poolco proposal, SCE would no longer sell power to its customers under COS/ROR ratemaking. It would sell all generation into the pool and receive the pool price. For its retail customers, it would buy back the necessary capacity and energy at the pool price. If the pool a well functioning competitive market, no regulation of price would be necessary. SCE acknowledges that it has market power over its retail customers and could impact the pool price. Thus, it proposes to accept the lower of market revenues or GIRR as its revenues. It also indicates that some of the difference between the market price and index would be captured in a "Transition Mechanism Credit."

Ignoring the fixed payment component for a moment, SCE's proposal operates much like a price cap. The utility can price at the cap but is free to go below it. The pool will determine what the market price for generation is, and SCE must sell power at the pool price even if it is below SCE's cap (Figure A-4). If the pool price rises above SCE's cap, SCE must provide service at the cap.

Figure A-4. SCE's Generation PBR Plan: Revenues When Market ("Exchange") Price is Above and Below PBR Index (Source: SCE 1995)



Although the mechanism operates like a price cap on the margin, it also includes a large base energy portion (GFC in Equation 11). This payment, which is like a revenue cap, recovers all the fixed costs of SCE's fossil fuel plants, including coal plants. For this payment, SCE guarantees a fixed amount of capacity and energy. The base energy payment also includes the fuel payments for the guaranteed base quantity of energy. The base quantity is larger than the output of SCE's coal plants, so the fixed portion of SCE's mechanism has the effect of being like a capacity-factor incentive mechanism for SCE's coal plants. SCE says it will subject the base energy payment to an annual productivity offset but provides no details.

As noted in SCE's fossil fuel revenue equation, the incremental energy payment portion relies on heat rates, emission outputs, gas prices, and emission credit prices. The first two factors (heat rates, emission output curves) would be set ahead of time. The latter two components (gas and emission prices) would be indexed using a predetermined formula.

With this mechanism, SCE clearly has an incentive to keep its costs from rising above the cap. Actual costs above the cap are a pure loss to the company, subject perhaps only to its proposed earnings sharing mechanism. Below the cap, SCE also has an incentive to control costs. If it can lower its costs, it can bid at the indexed rate and keep the cost savings. In situations where its costs are below the indexed cap, the utility may choose to bid below the cap to increase sales. Because it chooses what price it bids into the pool, it has a strong incentive to control costs. This mechanism would presumably replace SCE's existing FAC mechanism where rates are trued up to actual costs subject only to prudence reviews.

Unique to SCE's mechanism is the inclusion of emission costs in the cost index. SCE would only include emissions that have become tradable under the "RECLAIM" emission trading program that has been set up in the South Coast Air Quality Management District. The RECLAIM program covers primarily NOx and volatile organic compounds. Because the RECLAIM program is an existing emission trading program, SCE's emission price component reflects its actual opportunity costs and does not represent a societal externality adder.

Notably absent from SCE's generation PBR plan is treatment of nuclear and purchased power generation expenses. Nuclear power is excluded from both the Poolco mechanism and SCE's generation PBR plan. SCE has recently negotiated a settlement regarding its nuclear power plants that places performance risk on the company. Thus, SCE will baseload the operation of the nuclear plants, and revenue recovery is excluded from the PBR plan.

Regarding purchased power, SCE has proposed that it recover the difference between its existing contract prices and pool prices in a transition cost surcharge. Although proposals have been made to give SCE an incentive to buy out or buy down above-market contracts, the existence of the transition cost surcharge effectively guarantees recovery of existing purchased power contracts. As part of poolco, SCE may make additional net purchases of power, which will occur whenever pool purchases for retail customers exceed SCE's generation and purchases from existing power contracts. In those situations, SCE, by taking all up side cost risk, appears to betting that the market price of purchase power will stay below the market price of gas-fired generation for the term of this PBR plan.

A.10.6 Service Quality Incentives

Please see the Performance Incentives discussion of Section A.10.5.

A.10.7 Rate Performance Targets

Please see the Performance Incentives discussion of Section A.10.5.

A.10.8 Treatment of DSM

SCE proposes that for both DSM and R&D costs be included under the T&D revenue index, but that these revenue categories be subject to a special one-way balancing account. Under this accounting treatment, revenues collected for these purposes but not spent would be held over for future projects or refunded to the customers.

A.10.9 Coordination of Multiple Goals

There is no explicit means of coordinating multiple incentive goals.

A.10.10 Earnings Sharing Mechanism

The company proposes a symmetrical earnings sharing mechanism. Within ±150 basis points of the benchmark ROR[4], the shareholders are at risk for 100% of all variation in earnings. Between 150 and 300 basis points variations in earnings are shared 50%/50% between shareholders and customers. If the annual variation is greater than ±300 basis points, a general rate case would be initiated to review the mechanism and reasses rates.

The benchmark would initially be set as the authorized ROR in the 1995 GRC and would be adjusted each year. The adjustments would reflect the recorded average annual costs for the embedded costs of debt and preferred stock and the authorized return on common equity from the Trigger Mechanism (see discusion in Section A.10.5 above). These averages would

4 This rate of return covers the company's entire rate base (about $11 billion) not just the nongeneration potion ($6 billion) (California Department of General Services et. al. 1995).

be weighted using weights set in the 1995 GRC. Because debt is indexed to costs, the power of this incentive is less than 100 percent.

A.10.11 Z factors

The company identified four categories of Z factors:

- Major changes in mandatory fees and taxes,
- Major regulatory changes,
- Major claims against SCE and/or required modifications associated with exposure to nuclear radiation or electromagnetic fields, this does not however include legal fees, and
- Major accounting changes.

To insure that these Z factors are not abused, they would have to be authorized on a case-by-case basis and be individually larger than $10 million. Furthermore the $10 million threshold would act be a deductible. Therefore, only costs above the $10 million would be collected through a rate adjustment.

A.10.12 Off Ramps

In the event that the company's earnings vary more than 300 basis points from the benchmark ROR, a general rate case would be initiated to review the PBR mechanism (see Section A.10.10 above).

A.10.13 Pricing Flexibility

The PBR mechanism does not explicitly affect pricing or pricing flexability.

A.10.14 Alternative Proposals

Two alternative proposals were filed, one by a group of intervenors including environmental groups and consumer advocates, and one by the CPUC's Division of Ratepayer Advocates (DRA). The intervenors proposed a revenue per customer mechanism, and DRA proposed a rate cap.

Key elements of intervenor proposal

The intervenor proposal is based on a revenue per customer cap of about \$500. Each year this would be indexed according to the following formula:

$$RCP_t = RCP_{(t-1)} \times (1 + I - X) \qquad \textbf{(A-12)}$$

where:

RPC_t	=	Revenue per customer in year t,
I	=	Inflation as measured by the Handy-Whitman Utility Construction Cost Index, and
X	=	A productivity offset of 4%.

There would be no extra customer growth allowance (California DGS et al. 1995) .

Key elements of DRA proposal

DRA proposes two different rate caps, one for customer access services ("T&D" or "nongeneration") and one for generation services. DRA has not spelled out the latter in detail except to say that it would be based on a market price. The former would be based on the following formula:

$$P_t = P_{(t-1)} \times (1 + CPI - O - X - SF - RCB) \qquad \textbf{(A-13)}$$

where:

CPI	=	The Consumer Price Index,
O	=	A 1% CPI overstatement factor,
X	=	A 1% productivity offset,
SF	=	A 0.5% stretch factor, and
RCB	=	A 2.5% regional competitive benchmark.

The adjustment portion of this formula can be simplified to CPI - 5% (DRA 1994).

A.11 San Diego Gas & Electric

SDG&E, a combination gas and electric utility, has a million customers, retail sales of 15 terawatt-hours, and retail revenues of $1.4 billion.

A settlement was reached between three parties in SDG&E's PBR plan application which lead to the filing of a joint proposal in December 1993. This proposal was largely approved by an administrative law judge and then by the CPUC in August 1994. Our summary is primarily based on the joint testimony and the judge's proposed decision (SDG&E, DRA et al. 1993; Wetzell 1994).

A.11.1 Relationship to Competition and Restructuring

SDG&E's PBR proceedings dates back to its 1992 application, before the California Public Utilities Commission (CPUC) instituted its investigation of electric industry restructuring (I/R 94-04-031) (CPUC 1994b). Although the CPUC's decision could impact SDG&E's PBR mechanisms, the fact that they are functionally separated (base rate, gas procurement, and generation and dispatch) makes them relatively well-suited for later unbundling.

A.11.2 Term

This is a five-year base rate mechanism started with the 1993 general rate case. The generation and dispatch and gas procurement mechanisms each have terms of two years. All are all considered "experimental."

A.11.3 Type

SDG&E uses a broad base-rate revenue index with profit sharing and a two-year experimental generation and dispatch incentive. SDG&E's five-year plan is best characterized as a revenue index rather than a rate index. The company is not held to a sales forecast over the five years. Further, rates, once set, are subject to full or partial sales balancing account treatment. Thus, the company is not given a strong financial incentive to maximize sales as a way to improve efficiency. The company also has two other revenue index incentive mechanisms, one for generation and dispatch costs and the other for gas procurement. Although the gas procurement mechanism does affect the company's electric division gas purchases, the mechanism is not covered here.

A.11.4 Scope

Most electric revenues are subject to the adopted PBR mechanisms. After the 1993 test year, the base-rate revenue index mechanism computes base-rate revenues automatically from the formulas involving O&M and capital-related revenues. The generation and dispatch mechanisms nominally covers all fuel-related costs although some important fuel costs, such as fossil fuel prices and nuclear fuel prices, are subject to automatic pass-through mechanisms. (Electricity department gas costs are covered by the separate gas incentive mechanism.) DSM revenues are generally excluded from the broad PBR plan and are, instead, covered by a targeted incentive mechanism.

A.11.5 The Incentive Mechanisms

Base Rate Mechanism

Base revenues were set in the 1993 GRC. They are divided into two categories: O&M and capital-related. Each category has its own adjustment mechanism, which is calculated toward the end of the calendar year to determine the allowed revenues for the following year. The experimental generation and dispatch mechanisms covered later on in this section.

O&M Revenues

Base O&M revenues are calculated separately for the electric and gas divisions. All O&M expenses are included except those related to nuclear operations. The resulting O&M is adjusted upward for franchise fees and uncollectibles to obtain a meaningful revenue requirement.

These O&M expenses are divided into nonlabor, nonfuel O&M, and labor O&M. The nonlabor costs are

Box A-1

REVENUES ALLOWED O&M FORMULA

$$(O\&M_{nonlabor} \text{ X } (1+ \text{FERC index}) + O\&M_{labor} \text{ X } (1 + CPI_{t-1})) \text{ X } (1+ 58\% \text{ X } (\%\Delta Cust_{t-1} - 1.5\%))$$

SAMPLE CALCULATION

Assumption: 1993 GRC O&M revenues are $1,000 of which $500 are labor and $500 nonlabor.

Near the end of 1993:
- Nonlabor costs escalated by FERC index of 0.5%. (e.g. $500 X 100.5%= $502.50)
- Labor costs escalated by CPI for 1993 of 2.0%. (e.g. $500 X 102.0%= $510)
- The resulting O&M costs, $1,12.50, are adjusted for 58% of the sum of customer growth between 1993 and 1994 (2%) minus the 1.5% productivity factor. (e.g. $1012.50 X (1+58% X (2%-1.5%)) = $1015.44)

escalated according to the FERC account cost indexes for electric and gas utilities in the U.S. (As published in DRI/McGraw Hill (DRI) Utility Cost Information Service). The labor O&M is escalated according to the Consumer Price Index lagged one year and also adjusted by a customer growth/productivity factor. This factor is 58% of the sum of the percent change in active meters from one year to the next minus a 1.5% productivity factor based on the National Index of Output per Hour for Nonfarm Business from 1960-1990. Box A-1 contains the formula for allowed O&M revenues as well as a sample calculation.

Capital-Related Revenues

Base capital costs are also divided into two types, capital plant additions and capital-related revenue. Plant additions are further divided into three categories: (1) network plant additions, (2) nonnuclear generation plant additions, and (3) nuclear generation plant additions. The first of these is determined by a regression formula based on the change in the number of customers in the prior two years and is adjusted for retirements. Box A-2 explains how allowed network plant additions are calculated. The second category, generation plant additions, is based on a three-year moving average of past nonnuclear generation net plant additions. The nuclear generation plant addition revenues are excluded from the PBR mechanisms.

Box A-2

CALCULATING NETWORK PLANT ADDITIONS

The % gross additions for a subject year* = $4.23\% + .52\% \times \%\Delta Cust_{sub\ yr.-1} - 0.28\% \times \%\Delta Cust_{sub\ yr.-2}$

The total gross adds for a subject year = %grossadds X capitalstock(in Dec. of sub. yr. -1)

The gross adds are converted into nominal dollars in the subject year using the Handy-Whitman Index for Total Plant—All Steam—Pacific Coast Region.

Net adds are determined by subtracting retirements, which were adopted in detail in the 1993 GRC.

*The subject year is the year that the revenues will actually be collected in. Thus near the end of 1993, PBR revenues were calculated for subject year 1994.

Taxes are treated as pass-throughs and are adjusted each year to reflect law. Depreciation rates are set as a fixed percent of gross plant, which includes the results of the formula for gross plant additions. Thus, the revenue requirement for any subject year (e.g. 1994) is the prior year's (e.g. 1993) requirement adjusted separately for O&M and capital-related revenues. The company's ROR and ROE from the resulting base rate revenue continue to be determined annually in a cost of capital proceeding.

Performance Indicators Incentive

The incentive mechanisms also include a Performance Indicators Incentive. This incentive is pegged to employee safety, customer satisfaction, system reliability, and a national rate comparison. Depending on the company's performance, it can earn up $19 million in rewards or pay up to $21 million in penalties (about 130 and 145 ROE basis points respectively). Table A-11 presents the range of rewards and penalties for each indicator.

Table A-11. Maximum Performance Rewards & Penalties

Indicator	Reward	Penalty
Employee Safety	$3 million	$5 million
Customer Satisfaction	$2 million	$2 million
System Reliability	$4 million	$4 million
Rate Comparison	$10 million	$10 million

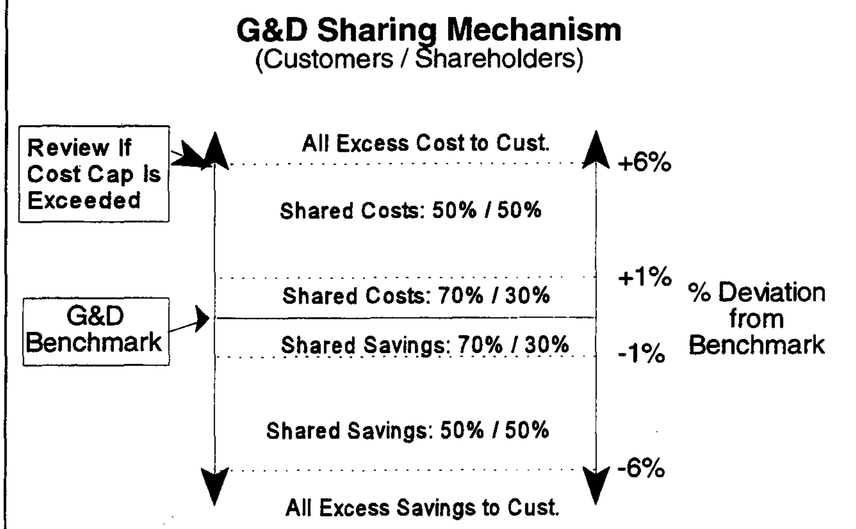
Employee safety is measured by the Occupational Safety and Health Administration's lost time frequency standard. Customer satisfaction is measured through the Customer Service Monitoring Service and the index is gauged to the number of "very satisfied" responses. This indicator is discussed in greater detail in Section A.11.6 below. System reliability is measured by a variation of the System Average Interruption Duration Index with a benchmark of 70 minutes. The rate comparison index is discussed further in Section A.1.7 (SDG&E 1993).

Generation and Dispatch Incentive Mechanism

This two-year experimental mechanism ran from August 1993 through July 1995. The goal was to give the company an incentive to control some of its costs related to generation and dispatch (G&D). The benchmark for this incentive is based on the CPUC's Energy Cost Adjustment Clause (ECAC) forecast which in turn relies on the ELFIN model to predict G&D costs. ECAC incorporates the cost of fuel, purchased power energy and demand charges, power sales, and wheeling and transmission expenses.

The G&D benchmark is trued up monthly to account for actual variations in loads, peaks, gas and oil expenses, QF purchases, QF energy and capacity expenses, and new test heat rates after plan overhauls. Although the justification for truing up oil prices and heat rates is not clear, the gas procurement incentive, as mentioned above, already provides an incentive to the company as a whole to purchase gas as efficiently as possible. The key factors that are not trued up include forced outage rates, maintenance outage rates, fuel inventory costs, economy energy quantity and price, wheeling, and short and long-term firm capacity contracts.

Figure A-5.



Adapted from Report Prepared by Vantage Consulting, Inc. (1995)

With customers the company shares the costs or savings from beating or losing against the benchmark as long as the difference is not greater than ±6%. Above this level all benefits and costs go to the customers (Figure A-5).

A.11.6 Service Quality Incentives

As discussed above, there is a performance incentive pegged to customer satisfaction. This is based on the results of the customer service monitoring system. The target is 92% of customers responding "very satisfied." The range for rewards or penalties is ± 3%. The reward or penalty is $333,333 for each 0.5% change in "very satisfied" responses.

A.11.7 Rate Performance Targets

As discussed above, a performance incentive is pegged to the company's rates as a percent of the national average in any given year. The target for 1994 is the most complex. The company earns no reward or penalty if its rates are within 1% of 137% of the national average for that year. There is also an asymmetric range in 1994 of +5% and -6%. In all other years there is no 1% deadband, and the range is ±5%. The targets for 1995, 1996, 1997, and 1998 are 136%, 135%, 133.5% and 132% respectively. Within the allowable range, each half a percentage point above or below the national average results in a $1 million (approximately seven basis points ROE) reward or penalty.

A.11.8 Treatment of DSM

DSM expenditures are excluded from both the base rate and generation and dispatch incentive mechanisms. Further, to avoid pressures to reduce DSM costs in order to win the rate performance reward, a PBR/DSM adjustment mechanism was created. This mechanism provides a constant level of reported DSM revenues for the purpose of deriving the average system rate used in the rate performance target incentive. The mechanism is based on the authorized DSM revenues from the 1993 GRC and is adjusted each year to reflect changes in the base amount of DSM revenues authorized. As a result, changes to DSM budgets by the company cannot affect the system average rate used for comparison purposes. Finally, SDG&E has retained shareholder incentive mechanisms that reward the company, based, in part, on the estimated net resource value of the DSM programs.

A.11.9 Coordination of Multiple Goals

The performance index incentive for rate and the nonprice factors are conditional on each other. In other words, if the company receives a penalty on either the rate comparison or on the nonprice factors as a group, then the company loses a percentage of its reward for the other factor. Nonprice factors include all the performance indicators mentioned above in Section A.11.5 except the rate comparison indicator. The percentage achievable from either factor is scaled down as the size of the penalty for the other factor increases. For example, in 1994 if the company's rates are 0.5% above the benchmark of 137% (of the national average), then the company can only receive 90% of any rewards from nonprice factors. If the company's rates are 4.5% above the national average, however, the company can only earn 10% of any rewards from nonprice factors. The penalty ranges from 100% to 0%. In this way the company does not have an incentive to sacrifice one type of performance for the other.

A.11.10 Earnings Sharing Mechanism

If the company's combined gas and electricity returns for a year are less than 100 basis points over the authorized ROR (about 200 ROE basis points[5]), the company's shareholders are allowed to keep the entire difference. If the returns are between 100 and 150 basis over the authorized ROR, the company must share the extra 75%/25% between shareholders and

[5] One ROR basis point is approximately equal to two ROE basis points given that most utilities are capitalized half through equity and half through long-term debt.

customers. Above 150 basis points, the company must share 50%/50%. The company's shareholders have to absorb all losses from returns below the authorized ROR.

A.11.11 Z factors

Many costs are passed through to the customers. These include nuclear generation related costs, depreciation, taxes, and any plant approved by the CPUC in a Major Additions Adjustment Clause proceeding.

A petition for modification may be filed in the event that the company's base rate revenue requirement is affected by more than $500,000 (approximately three ROE basis points) and this occurrence is beyond management control. Applications for relief can be filed to account for changes in certain exogenous cost categories including local air pollution control and hazardous waste cleanup.

A.11.12 Off Ramps

If the company reports annual combined gas and electric returns of 150 basis points below the authorized ROR (approximately 300 ROE basis points or ten times the modification trigger) a variety of parties may request a review of the PBR mechanism. If annual returns are 300 basis points below the authorized ROR, a review is automatically triggered.

A.11.13 Pricing Flexibility

The PBR mechanism did not include any extra pricing flexibility.

A.12 Tucson Electric Power

Tucson Electric Power (TEP) serves about 295,000 customers, producing 7,600 GWh a year and generating $590 million in revenues from retail sales.

In June of 1995, TEP filed an incentive rate plan. As of mid July, the plan was under initial review by the Arizona Corporation Commission (ACC). This summary is based on the testimony of the Vice President of Wholesale/Retail Pricing and System Planning, Steven J. Glazer, and personal communications with Mr. Glazer (Glazer 1995a; Glazer 1995b).

A.12.1 Relationship to Competition and Restructuring

Although Arizona is not officially investigating restructuring, TEP's proposal is heavily steeped in the language of competition. The company claims that its primary motivation for the proposal is to increase competitive efficiency. For example, when asked to summarize the reasoning behind the pricing flexibility proposal, Mr. Glazer responded: "In a word, competition. As TEP has discussed throughout its testimony in this proceeding, competitive market forces are changing the electric industry..." (Glazer 1995, pg. 14).

A.12.2 Term

Five years.

A.12.3 Type

TEP's proposal consists mainly of a price cap on all residential rates and a specific cost target for fuel and operations and maintenance expenses. The company is also requesting pricing flexibility below the residential price cap and on wholesale sales. Some of the earnings under these mechanisms would be shared 50%/50% with customers.

A.12.4 Scope

TEP's proposal is wide ranging and covers all of its operating costs though fuel and O&M expense are particularly targeted.

A.12.5 Incentive Mechanisms

TEP's incentive mechanism is very simple. In the interim between the implementation of this proposal and the next rate case, the company's overall rates would be capped at the level set in the proceeding. If the company can reduce its costs, it can keep some of the savings. On the other hand, if TEP's costs go up, the company has to pay for the costs out its profits.

More specifically, the company also proposed that its allowed fuel and operations and maintenance revenues be fixed at 5.08 cents per kWh. This is based on expenses in 1994 of $387,370,000 and total sales of 7,620,731 MWh. If the company can reduce its costs below this cap over the course of the five-year period, it would share these savings 50%/50% with customers at the next rate proceeding. The company does leave open the possibility that the cap will be subject to "various pro forma adjustments" at the next rate proceeding.

There is no sharing for nonfuel and non-O&M expenses. At the next rate case, the company specifically proposes that all costs would be evaluated on a "go-forward" basis.

A.12.6 Service Quality Incentives

There are no service quality incentives in the plan.

A.12.7 Rate Performance Targets

There are no rate performance targets in the plan.

A.12.8 Treatment of DSM

There's no change in DSM. The company does have a range of DSM incentives, but these are not impacted by the proposal.

A.12.9 Coordination of Multiple Goals

None explicit.

A.12.10 Earnings Sharing Mechanism

Company proposes to share any savings in fuel and O&M expenses below the 5.08 cents/kWh cap 50%/50% with customers. This sharings only applies to savings. Any cost overruns are paid for by the company.

TEP also proposes to share 50%/50% with customers any profits from wholesale sales. In this case profits would be the difference between the marginal cost of the power and the actual sales price. (For more discussion of wholesale sales see Section A.12.13 below.)

A.12.11 Z factors

While no specific Z factors are mentioned, the company does leave open the option for "various pro forma adjustments" to its fuel and O&M cap. This includes a wide range of unforeseeable events.

A.12.12 Off Ramps

There are no explicit off ramps.

A.12.13 Pricing Flexibility

TEP request two types of pricing flexibility. On the retail side, the company proposes that rates be capped for the next five years at the level set in proceeding. Below this cap, though, the company requests the ability to set prices for retail customers via special contracts without commission approval.

On the wholesale side, the company requests a reformulation of how costs and new generation facilities are allocated between FERC and ACC. The goal of this shift is to allow the company to charge down to marginal cost on wholesale sales instead having to charge the company's average cost. The company then plans to share with customers half of the difference between the marginal cost and the cost the company actually negotiates for its sales.

LBNL's Incentive Power Index and Index Backcast

B.1 LBNL's Incentive Power Index

In Volume I, Chapter 3, we defined the LBNL Power index as follows:

$$POWERNDX = \sum_{i}^{N} f_i \; x \; b_i \; x \; T_i \, . \qquad \textbf{(B-1)}$$

where:

POWERNDX	=	LBNL Incentive Power index (years at 100% incentive power)
b_i	=	shareholder incentive power of revenue category i (percent)
f_i	=	category i revenues as a percent of total revenue requirement
T_i	=	term of incentive mechanism applicable to category i

Our assumptions and calculations for the LBNL Incentive Power Index are shown in Table B-1. Our general method was as follows. For each of the nine utilities subject to a rate or revenue caps, we collected recorded 1993 revenues by cost category (EIA 1995). Cost categories included nonfuel O&M, depreciation, interest on debt, taxes, equity return, and fuel costs. Fuel costs were also disaggregated into fossil and hydroelectric, nuclear, and purchased power (including purchased from nonutility generators). We turn the revenues into percentages of total 1993 revenues. For each cost category, we ascribe a with- and without-PBR marginal incentive rate. Table B-1 describes the assumptions we made on incentive power in each case. With an incentive power ascribed to each cost category, we can compute a revenue-weighted average incentive rate, both with and without PBR. We then multiply the weighted average incentive rates by the term of the PBR in the "with" case and our understanding of existing regulatory lag in the "without" case. These final products are the LBNL Incentive Power Index values. The units of the index are years at a 100% marginal incentive rate.

To simplify calculations, we sometimes perform the following procedure. Some PBR plans have multiple terms. For example, one term applies to fuel costs and another term to base rates. We typically show the term for the base rate mechanism and adjust the incentive rate on the fuel revenues to compensate for the different term. For example a utility with an annual FAC with no true up, is ideally stated as an incentive rate of 100% and a term of 1 year. If the base-rate term is three years, however, we, in some cases, show the term for both the FAC and base rates as three years but show the marginal incentive rate of the FAC as 33%. There is no loss in accuracy from this simplification procedure.

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

	Item:	EIA Sources:		Generic Utility Nos. 1 and 2: U.S. IOU avg./total				San Diego Gas & Electric Co.			
	RECORDED OPERATING DATA	(1993 RECORDED DATA FROM EIA (1995))									
		Table	pp., LIne	Dollars				Dollars			
	Electric Operating Revenues	37	1, 1	176,354,365				1,513,735			
	Electric Depreciation Exp.	37	1, 4	16,622,229				177,420			
	Electric Amortization Exp.	37	1, 5	1,476,507				3,343			
	Electric fed Inc. Tx	37	1, 9	7,145,892				99,342			
	Electric other Inc. Tx	37	1, 10	1,151,008				21,297			
	Total Electric Utility Operatin	37	1, 18	146,118,013				1,271,419			
	Net Interest Charges	37	3, 9	14,700,488				91,423			
	Net Income	37	3, 13	17,891,198				218,715			
	Net electric utility plant	38	1, 5	363,892,459				2,531,912			
	Net all utility plant	38	1, 18	393,829,243				3,117,633			
	Ratio	38		92%				81%			
	Cash Outlays for Utility Plan	39	1, 16	-25,534,859				-347,811			
	Total Nuclear Power Produc	41	1, 36	11,607,298				94,802			
	Purchased power	41	2, 20	27,715,512				325,966			
	Total Power Production Exp	41	2, 24	76,796,796				642,635			
	DSM Expenditures										
	LBNL INCENTIVE INDEX CALCULATIONS			U.S. Total IOUs		Incentive Power				Incentive Power	
						No. 1: 3 yrs w/ FAC	No. 25 yrs w/o FAC				
	Expenses			Dollars	Pct			Dollars	Pct	w/o PBR	w/ PBR
A	Nonfuel O&M			42,925,581	24%	100%	100%	327,382	22%	100%	100%
A	DSM expenditures			0				0			
A	Depreciation Expense			18,098,736	10%	100%	100%	180,763	12%	100%	100%
	Fuel										
A	Fossil & Hydro			37,473,986	21%	0%	100%	221,867	15%	0%	10%
A	Nuclear			11,607,298	7%	0%	100%	94,802	6%	75%	75%
A	Purchased Power (incl. QF)			27,715,512	16%	0%	100%	325,966	22%	0%	12%
	Subtotal Total Fuel			76,796,796	44%			642,635	42%		
	Total expenses including inc. taxes			146,118,013	83%			1,271,419	84%		
	Total expenses less inc. taxes			137,821,113	78%			1,150,780	76%		
A	Net Interest Charges			13,583,036	8%	100%	100%	74,247	5%	67%	60%
A	Net Income to Equity			16,653,316	9%	100%	100%	168,069	11%	67%	60%
A	Income Taxes			8,296,900	5%	100%	100%	120,639	8%	67%	60%
	Total Profit + Assoc. Tax			38,533,252	22%			362,955	24%		
	Total Electric Utility Revenues			176,354,365	100%	56%	100%	1,513,735	100%	54%	57%

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

Item:	EIA Sources:		Generic Utility Nos. 1 and 2: U.S. IOU avg./total				San Diego Gas & Electric Co.			
Power Index Computation										
Years In Force					3	5			3	5
Power Index Total Value					1.6935941	5			1.62753025	2.834698
Notes:										
Capital outlays OR depreciation should be used in composite index, but not both										
A = avoidable cost										
DSM prorgram costs and targeted shâreholder incentives, if any, ARE IGNORED AT THIS TIME. DSM is implicitly included in nonfuel O&M.										
							Assumptions		Asummptions	
SUMMARY OF ASSUMPTIONS USED IN INDEX CALCUALTIONS							w/o PBR		w/ PBR	
Non Fuel Costs							Assume 100%.		Assume 100%.	
Fuel Costs							Under prePBR ECAC, full pass through except for nuclear costs, which we assume the same as SCE's.		G&D mechanisms appears to incentivize availability, gas prices, purchased power. Need to adjust for 2-year term. Assume 50-50 (second-tier) sharing.	
ROE and Taxes							Annual cost of capital proceeding		Litigated, annual cost of capital rpceeding is retained. Assume, however, there is risk for plant in service. Assume a 50-50 split.	
DSM									DSM is excluded from PBR. Separate shareholder incentives.	

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

	Item:	NMPC				PG&E (base rate + nuclear)				SCE T&D + G PBR			
	RECORDED OPERATING DATA												
		Dollars				Dollars				Dollars			
	Electric Operating Revenues	3,308,122				7,877,629				7,387,226			
	Electric Depreciation Exp.	253,948				923,323				782,915			
	Electric Amortization Exp.	-354				23,067				109,314			
	Electric fed Inc. Tx	106,660				512,332				264,472			
	Electric other Inc. Tx	0				175,090				89,355			
	Total Electric Utility Operatin	2,826,209				6,386,722				6,222,198			
	Net Interest Charges	289,564				769,934				433,064			
	Net Income	271,831				1,065,495				678,046			
		0				0				0			
	Net electric utility plant	5,854,312				13,696,225				12,149,148			
	Net all utility plant	6,850,021				18,755,280				12,303,082			
	Ratio	85.46%				73.03%				98.75%			
		0				0				0			
	Cash Outlays for Utility Plant	-254,327				-1,259,136				-889,507			
		0				0				0			
	Total Nuclear Power Produc	189,711				291,871				359,553			
	Purchased power	868,422				1,594,662				2,497,466			
	Total Power Production Exp	1,341,271				2,816,180				3,443,974			
	DSM Expenditures												
	LBNL INCENTIVE INDEX CALCULATIONS			Incentive Power				Incentive Power				Incentive Power	
	Expenses	Dollars	Pct	w/o PBR	w/ PBR	Dollars	Pct	w/o PBR	w/ PBR	Dollars	Pct	w/o PBR	w/ PBR
A	Nonfuel O&M	1,124,684	34%	100%	75%	1,936,730	25%	100%	100%	1,532,168	21%	100%	100%
A	DSM expenditures	0				0				0			
A	Depreciation Expense	253,594	8%	100%	75%	946,390	12%	100%	100%	892,229	12%	100%	100%
	Fuel												
A	Fossil & Hydro	283,138	9%	13%	40%	929,647	12%	0%	0%	586,955	8%	0%	100%
A	Nuclear	189,711	6%	13%	40%	291,871	4%	100%	100%	359,553	5%	75%	75%
A	Purchased Power (incl. C	868,422	26%	13%	40%	1,594,662	20%	0%	0%	2,497,466	34%	0%	11%
	Subtotal Total Fuel	1,341,271	41%			2,816,180	36%			3,443,974	47%		
	Total expenses including inc.	2,826,209	85%			6,386,722	81%			6,222,198	84%		
	Total expenses less inc. taxe	2,719,549	82%			5,699,300	72%			5,868,371	79%		
A	Net Interest Charges	247,473	7%	100%	75%	562,252	7%	67%	100%	427,646	6%	67%	100%
A	Net Income to Equity	234,440	7%	100%	75%	928,655	12%	67%	100%	737,382	10%	67%	100%
A	Income Taxes	106,660	3%	100%	75%	687,422	9%	67%	100%	353,827	5%	67%	100%
	Total Profit + Assoc. Tax	588,573	18%			2,178,329	28%			1,518,855	21%		
	Total Electric Utility Revenue	3,308,122	100%	65%	61%	7,877,629	100%	59%	68%	7,387,226	100%	50%	69%

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

Item:	NMPC				PG&E (base rate + nuclear)				SCE T&D + G PBR			
Power Index Computation												
Years In Force			3	5			3	6			3	6.93
Power Index Total Value			1.945836	3.040466			1.762159	4.077359			1.505287	4.760373
Notes:												
Capital outlays OR depreciat												
A = avoidable cost												
DSM prorgram costs and tar												
	Assumptions		Asummptions		Assumptions		Asummptions		Assumptions		Asummptions	
SUMMARY OF ASSUMPTIONS USED IN INDEX CALCUALTIONS	w/o PBR		w/ PBR		w/o PBR		w/ PBR		w/o PBR		w/ PBR	
Non Fuel Costs	Assume 100%.		NMPC taking all downside risk on earnings but any upside goes to buy down regulatory assets rather than bottom line. Assume 50% on this value, giving total weighted average of 75%		Assume 100%.		Assume 100%.		Assume 100%.		Assume 100%.	
Fuel Costs	Assume 1-year FAC with 40/60 shareholder/ratepayer sharing. Downward adjustment for term.		Price cap subindex with initially 40%/60% shareholder/ratepayer sharing on fuel cost deviations for entire term.		Full FAC except for nuclear wich is subject to performance based contract at 100% incentive rate.		No change				Eighty nine percent of power purchases are from QF and I assume these are excluded. Note the 8 year term is included in the term of the PBR.. Assume that recent nuclear settlement has incentive rate of 75%.	
ROE and Taxes			Apparently indexed		Annual cost of capital proceeding		Cost of capital indexed. Assume at risk for both plant in service and cost of capital.		Annual cost of capital proceeding		Cost of capital indexed. Assume at risk for both plant in service and cost of capital.	
DSM			Expenses part of index. Shareholder incentives retained									

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

	Item:	Pacificorp (CA)				NYSEG				ConEd			
	RECORDED OPERATING DATA												
		Dollars				Dollars				Dollars			
	Electric Operating Revenues	2,505,882				1,527,362				5,145,010			
	Electric Depreciation Exp.	236,398				141,189				349,153			
	Electric Amortization Exp.	18,201				14,052				1,436			
	Electric fed Inc. Tx	108,865				32,942				241,498			
	Electric other Inc. Tx	14,203				0				0			
	Total Electric Utility Operatin	1,910,326				1,249,985				4,329,056			
	Net Interest Charges	257,307				139,497				298,143			
	Net Income	478,595				167,410				658,522			
		0				0				0			
	Net electric utility plant	7,130,159				3,470,744				7,804,414			
	Net all utility plant	7,131,361				3,920,146				10,143,894			
	Ratio	99.98%				88.54%				76.94%			
		0				0				0			
	Cash Outlays for Utility Plan	-627,780				-254,327				-660,754			
		0				0				0			
	Total Nuclear Power Produc	3				38,347				169,972			
	Purchased power	274,910				161,967				812,616			
	Total Power Production Exp	992,177				533,858				1,696,008			
	DSM Expenditures												
	LBNL INCENTIVE INDEX CALCULATIONS			Incentive Power				Incentive Power				Incentive Power	
	Expenses	Dollars	Pct	w/o PBR	w/ PBR	Dollars	Pct	w/o PBR	w/ PBR	Dollars	Pct	w/o PBR	w/ PBR
A	Nonfuel O&M	540,482	22%	100%	100%	527,944	35%	100%	100%	2,040,961	40%	100%	100%
A	DSM expenditures	0				0				0			
A	Depreciation Expense	254,599	10%	100%	100%	155,241	10%	100%	100%	350,589	7%	100%	100%
	Fuel												
A	Fossil & Hydro	717,264	29%	100%	100%	333,544	22%	13%	100%	713,420	14%	11%	11%
A	Nuclear	3	0%	100%	100%	38,347	3%	13%	100%	169,972	3%	11%	11%
A	Purchased Power (incl. C	274,910	11%	100%	100%	161,967	11%	13%	72%	812,616	16%	11%	34%
	Subtotal Total Fuel	992,177	40%			533,858	35%			1,696,008	33%		
	Total expenses including inc.	1,910,326	76%			1,249,985	82%			4,329,056	84%		
	Total expenses less inc. taxe	1,787,258	71%			1,217,043	80%			4,087,558	79%		
A	Net Interest Charges	257,264	10%	67%	100%	123,505	8%	100%	100%	229,382	4%	100%	100%
A	Net Income to Equity	338,292	13%	67%	100%	153,872	10%	100%	100%	586,572	11%	100%	100%
A	Income Taxes	123,068	5%	67%	100%	32,942	2%	100%	100%	241,498	5%	100%	100%
	Total Profit + Assoc. Tax	718,624	29%			310,319	20%			1,057,452	21%		
	Total Electric Utility Revenue	2,505,882	100%	90%	100%	1,527,362	100%	70%	97%	5,145,010	100%	71%	74%

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

Item:	Pacificorp (CA)				NYSEG				ConEd			
Power Index Computation												
Years In Force			3	3			3	3			3	3
Power Index Total Value			2.713225	3			2.091223	2.910093			2.119858	2.228269
Notes:												
Capital outlays OR depreciat												
A = avoidable cost												
DSM prorgram costs and tar												
	Assumptions		Asummptions		Assumptions		Asummptions		Assumptions		Asummptions	
SUMMARY OF ASSUMPTIONS USED IN INDEX CALCUALTIONS	w/o PBR		w/ PBR		w/o PBR		w/ PBR		w/o PBR		w/ PBR	
Non Fuel Costs	Assume 100%.		Assume 100%.		Assume 100%. Assume pre-PBR term is 3 years.		Assume 100%, but R&D is a pass through		Assume 100%.		Set at100%. This ignores the following allowed passthroughs: IPP capacity costs after 6 months, Pension and other post-employment benefits, 86% of any property tax change, and Renewables	
Fuel Costs	FAC was already eliminated before this PBR.		Continue status quo.		Assume a FAC with 40/60 shareholder/ratepayer sharing.. Adjust for 1-year term.		FAC is eliminated under settlement. NYSEG can pass through certain amounts of NUG renegotiation costs. $78 out of $92 million/year are NUG costs. We assume that the regulatory lag on 50% of these NUG costs are only 1 year (instead of 3).		Same as with PBR except for QF adjustment		FAC mechanism with 30%/70% shareholder/ratepayer sharing on fuel cost deviations. Adjust marginal rate for 1 year. 100% on QF energy costs for 18 months. QF purchases are 352/600 of total purchases.	
ROE and Taxes	Assume participation in cost of capital.		Assume no longer participating in cost of capital proceddings..								Revenue requirement is updated annually but to an indexed, rather than COS, number.	
DSM							Affordable energy program is a pass through.				Expenses passed through	

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

	Item:	CMP				TEP			
	RECORDED OPERATING DATA								
		Dollars				Dollars			
	Electric Operating Revenues	887,038				662,437			
	Electric Depreciation Exp.	39,560				66,911			
	Electric Amortization Exp.	12,182				7,273			
	Electric fed Inc. Tx	14,312				0			
	Electric other Inc. Tx	3,791				0			
	Total Electric Utility Operatin	786,971				583,350			
	Net Interest Charges	48,082				109,829			
	Net Income	61,303				-25,816			
		0				0			
	Net electric utility plant	1,077,020				2,003,048			
	Net all utility plant	1,078,844				2,003,048			
	Ratio	99.83%				100.00%			
		0				0			
	Cash Outlays for Utility Plan	-54,423				-47,995			
		0				0			
	Total Nuclear Power Produc	4,028				0			
	Purchased power	489,705				9,032			
	Total Power Production Exp	538,394				336,804			
	DSM Expenditures								
	LBNL INCENTIVE INDEX CALCULATIONS			Incentive Power				Incentive Power	
	Expenses	Dollars	Pct	w/o PBR	w/ PBR	Dollars	Pct	w/o PBR	w/ PBR
A	Nonfuel O&M	178,732	20%	100%	100%	172,362	26%	100%	75%
A	DSM expenditures	0				0			
A	Depreciation Expense	51,742	6%	100%	100%	74,184	11%	100%	100%
	Fuel								
A	Fossil & Hydro	44,661	5%	0%	100%	327,772	49%	100%	75%
A	Nuclear	4,028	0%	0%	100%	0	0%	100%	75%
A	Purchased Power (incl. C	489,705	55%	0%	61%	9,032	1%	100%	75%
	Subtotal Total Fuel	538,394	61%			336,804	51%		
	Total expenses including inc.	786,971	89%			583,350	88%		
	Total expenses less inc. taxe	768,868	87%			583,350	88%		
A	Net Interest Charges	48,001	5%	100%	100%	109,829	17%	100%	100%
A	Net Income to Equity	52,066	6%	100%	100%	-30,742	-5%	100%	100%
A	Income Taxes	18,103	2%	100%	100%	0	0%	100%	100%
	Total Profit + Assoc. Tax	118,170	13%			79,087	12%		
	Total Electric Utility Revenue	887,038	100%	39%	78%	662,437	100%	100%	81%

Table B-1. LBNL Incentive Power Index Data, Calculations, and Assumptions

Item:	CMP				TEP			
Power Index Computation								
Years In Force			3	5			3	5
Power Index Total Value			1.179129	3.913673			3	4.039218
Notes:								
Capital outlays OR depreciat								
A = avoidable cost								
DSM prorgram costs and tar								
	Assumptions		Asummptions		Assumptions		Asummptions	
SUMMARY OF ASSUMPTIONS USED IN INDEX CALCUALTIONS	w/o PBR		w/ PBR		w/o PBR		w/ PBR	
Non Fuel Costs	Assume 100%.		Assume 100%.		Term is not known; assume 3 years. Assume 100% rate		TEP sets a fuel and O&M target of over 5 c/kWh. This must include significant amounts of nonfuel costs. Assume 100% risk on upside, 50% sharing on downside for a weighted average of 75%	
Fuel Costs	Assume a full FAC.		FAC is eliminated except for QF costs. Assume 50% rate on QF costs per sharing on buyout/buydown.				See above	
ROE and Taxes								
DSM								

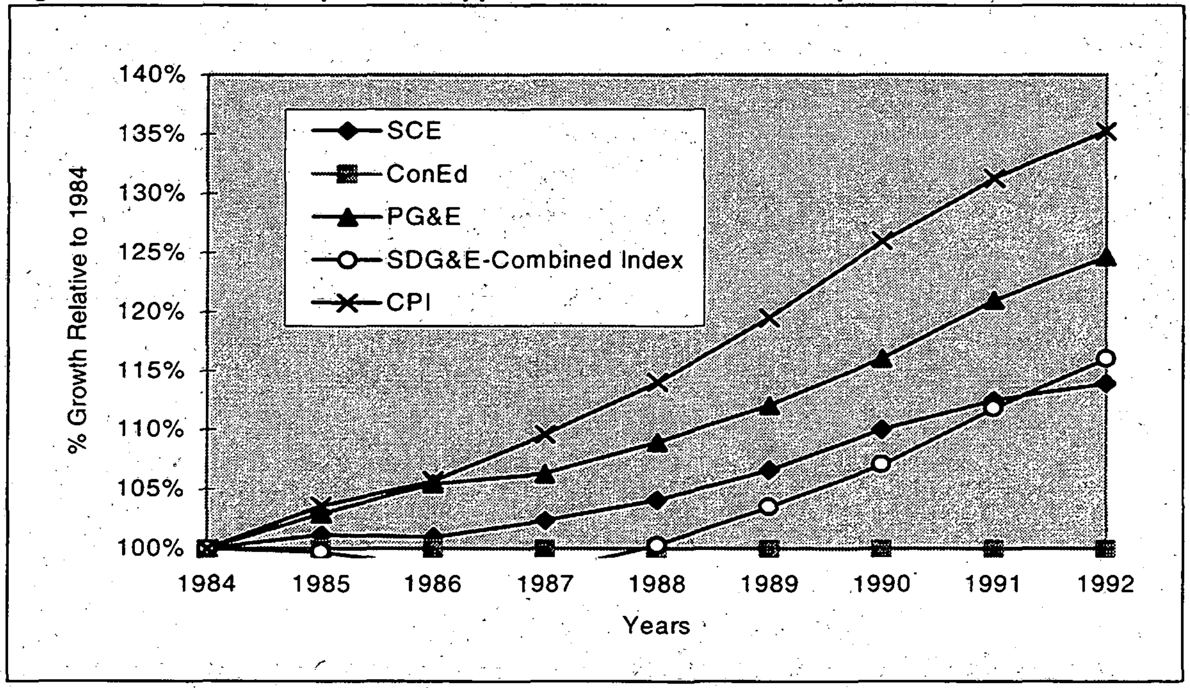
B.2 Historical Analysis (Backcast) of PBR Indices

The historical analysis is divided between price caps and revenue caps. The sliding-scale mechanisms used by Alabama and Mississippi were not examined and neither was NYSEG's plan because its caps are a yearly schedule of rate changes and not an index plan per se. An eight year period from mid-1984 to mid-1992 was chosen because eight years is the longest term for any actual or proposed PBR mechanism.

B.2.1 Price Cap Analysis

For this analysis two sets of data were collected. The first was the historical values of the different indices used in the four price cap PBRs examined: NMPC, CMP, PG&E for its large electrical manufacturing customer (LEMC) class, and PacifiCorp. The Consumer Price Index (CPI) for all urban customers for the entire U.S. and the Gross Domestic Product-Implicit Price Deflator are collected by the Bureau of Economic Analysis. The Producer Price Index for industrial electric power is collected by the Bureau of Labor Statistics. PacifiCorp uses four indices collected by DRI/McGraw Hill's Utility Cost Information Service. PacifiCorp provided a copy of this data. All the indices are presented in Tables B-2 through B-6. These numbers combined with the company-specific index formulas, detailed in Appendix A, provided the basis for the index summary shown in Figure B-1.

Figure B-1. Revenue Cap Indices Applied to Historical Data on a per-Customer Basis



The second set of data collected was the actual revenue and sales to ultimate customers or, in the case of PG&E, to its LEMC class. This information was found in EIA's *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*. This data was used to calculate average price per kWh in 1984 and in 1992 and thus to calculate a cumulative percent change with respect to 1984. These results along with the total percent change based on the PBR values provides the basis for Figure 3-1 in Volume I, Chapter 3. With regard to PG&E, EIA does not report LEMC directly and historically did not report industrial customers separate from commercial customer as far back as 1984. To adjust for this, we used the proportion of industrial class contribution to commercial and industrial revenues and sales in 1986 to estimate the industrial class contribution in 1984.

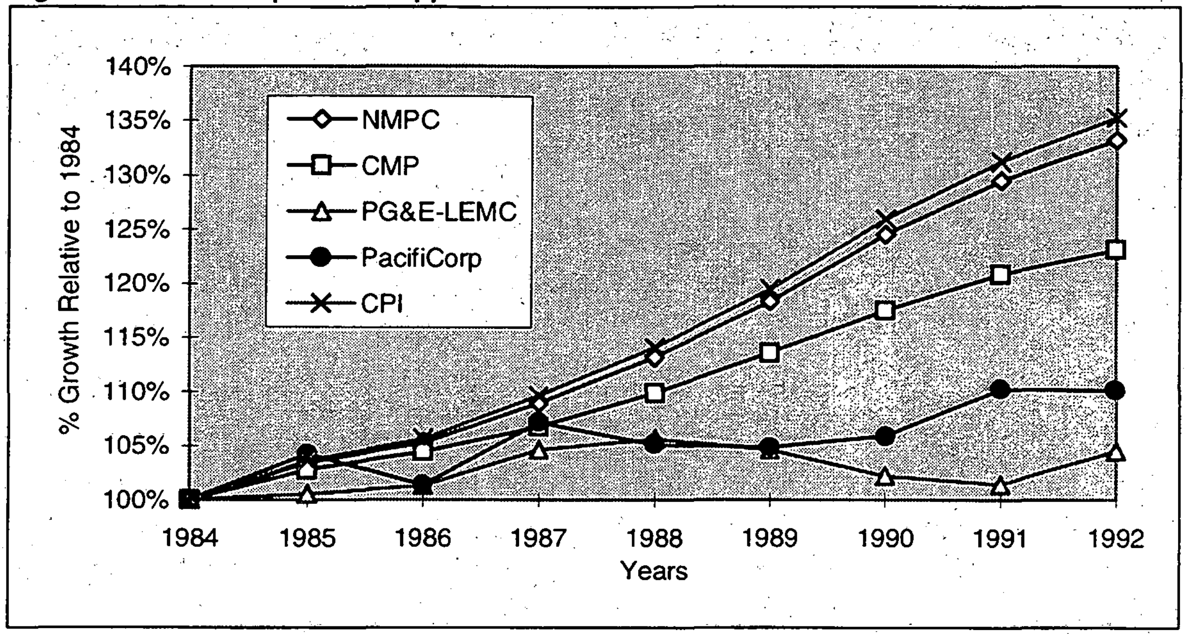
B.2.2 Revenue Cap Analysis

As with the price cap analysis, two sets of data were needed to do the revenue cap analysis. The first was the historical values of the indices used by the four revenue cap PBRs examined: SCE, ConEd, PG&E, and SDG&E. This included the CPI data plus two new indices both used by SDG&E. The first of these new indices is a weighted average of two internal costs indices which the company reports to FERC. The second is the Handy-Whitman Total Plant-All Steam Generation for the Pacific Region which was taken from the *Handy-Whitman Bulletin* number 141. This data also appears in Tables B-2 through B-6. This data was combined with historical numbers of ultimate customers found in EIA's *Financial Statistics of Major U.S. Investor-Owned Electric Utilities* and the PBR formulas detailed in Appendix A. First changes in revenues were calculated and normalized relative to 1984. Then this was converted in percent change in revenue per customer relative to 1984 by dividing the percent change in revenues by the percent change in customers. The results of these computations are presented in Figure B-2.

The second set of data collected was used to calculate actual base-rate revenues per customer in 1984 and 1992. This was based on the actual revenues from ultimate customers minus the total power production expenditures. This was then divided by the actual number of ultimate customers to produce the 1984 and 1994 data points. The change in these values and the change in the calculated PBR values is the basis for Figure 3-1 in Chapter 3.

Our goal was to provide a reasonable backcast of total indexed revenues for each utility. As a result, San Diego Gas and Electric's three separate PBR indices were combined for this analysis. To determine a change in indexed revenues relative to 1984, we picked first-year historical values for the three cost categories indexed—(1) nonnuclear, labor, (2) nonnuclear, nonlabor O&M, and (3) capital additions—and calculated corresponding dollar impacts on base-rate revenues. By summing the resulting revenue requirement stream we were able to calculate the relative change. The absolute values of this revenue stream are misleading because they depend on the first-year values, but we believe that our method computes the relative change of a combined index with reasonable accuracy.

Figure B-2. Price Cap Indices Applied to Historical Data



We made several assumptions or simplification when analyzing SDG&E's data:

- Not all of the company's revenues were indexed. Base-rate revenues (calculated again as the actual revenues from ultimate customers minus the total power production expenditures) were used to calculate the historical change relative to 1984, but SDG&E's three PBR mechanisms cover only a subset of base-rate revenues so there is not a perfect match between the index and the historical values.

- The first-year values of these three cost categories are not readily available and so they had to be estimated using EIA data.

- Converting the capital additions index, which is an allowable *expenditures* index, into *revenue requirement* was particularly difficult. In reality, the capital additions are depreciated over their useful life—often thirty years—and so only a small amount of any one year's additions are converted in to revenue requirement. Furthermore, the amount that is converted is added into the revenue requirement in to phases. Forty-five percent is added in the first year and 55 percent in the second. To estimate the impact on revenue requirements a simple ordinary least squares regression was run on the actual transmission and distribution capital additions, lagged one year, and the actual change in T&D-related revenues. Due to the one year lag the data set started in 1985 and ran through 1993. While the fit was not strong, it was the best of a variety of models we looked at. Since our goal was to calculate only the addition revenue requirements due to capital additions, was also had to estimate a first-year value for these data. One final note with respect to these calculations is that the capital additions index is limited to additions that are less than $50 million. While most network additions fall under this limit, we were unable to separate out those that did not from our data.

- To calculate the initial values for nonnuclear, nonlabor O&M and nonnuclear labor O&M, a two step process was used: (1) Nonnuclear total O&M was calculated by subtracting total nuclear O&M from total O&M; (2) the portions of nonnuclear total O&M attributable to labor was calculated using the ratio of total O&M salary and wages to total O&M. To calculate the initial values for the capital additions we summed the total transmission and distribution additions. To calculate the portion of revenues required to pay for network capital, the ratio of network (transmission and distribution) plant to total plant was applied to base-rate revenues.

Table B-2. Historical Values of PBR Mechanism Relative to 1984 Base Line

Year	Utility NMPC	Price Cap Plans CMP	PG&E-LEMC	PacifiCorp	Revenue Cap Plans SCE	ConEd	PG&E	SDG&E-NLO&M	SDG&E-LO&M	SDG&E-Cap adds	SDG&E	CPI
1984	1	1	1	1	1	1	1	1	1	1	1	1
1985	1.034	1.027	1.005	1.042	1.012	1	1.03	0.996	1.027	1.005	0.997	1.036
1986	1.053	1.044	1.013	1.014	1.01	1	1.055	0.977	1.044	1.001	0.985	1.057
1987	1.089	1.067	1.046	1.071	1.024	1	1.063	0.968	1.051	1.006	0.98	1.096
1988	1.132	1.098	1.057	1.051	1.041	1	1.089	0.993	1.066	1.061	1.003	1.14
1989	1.183	1.136	1.046	1.049	1.066	1	1.121	1.02	1.084	1.109	1.035	1.194
1990	1.245	1.175	1.022	1.059	1.1	1	1.16	1.039	1.109	1.151	1.07	1.26
1991	1.295	1.209	1.015	1.102	1.125	1	1.21	1.064	1.15	1.2	1.118	1.313
1992	1.332	1.231	1.045	1.101	1.139	1	1.246	1.071	1.187	1.255	1.16	1.353

Table B-3. Actual vs. Indexed Change in Average Prices & Revenues Per Customer Relative to 1984

	Utility NMPC	CMP	PG&E-LEMC	PacifiCorp	SCE	ConEd	PG&E	SDG&E	CPI
Historical	1.491	1.382	1.126	1.203	1.162	1.15	2.234	1.006	1.353
PBR	1.332	1.231	1.045	1.101	1.139	1	1.246	1.16	

Table B-4. Relevant Historical Utility Data

Utility		SCE			ConEd			PG&E			SDG&E		
Category		Base-rate revenues ('000)	Customers	ARPC	Base-rate revenues ('000)	Customers	ARPC	Base-rate revenues ('000)	Customers	ARPC	Base-rate revenues ('000)	Customers	ARPC
Year	1984	$2,487,566	3363599	$740	$2,413,735	2783589	$867	$1,659,993	3652073	$455	$600,067	838187	$716
	1985		3446797			2806326			3724876			873746	
	1986		3539709			2830949			3811246			917720	
	1987		3656309			2858998			3898992			967636	
	1988		3777344			2883956			3982941			1012706	
	1989		3889444			2908760			4076068			1052566	
	1990		3993065			2928555			4159209			1084577	
	1991		4055879			2938199			4228614			1103328	
	1992	$3,517,544	4094689	$859	$2,942,559	2950612	$997	$4,341,066	4275304	$1,015	$804,385	1117352	$720

Table B-5. Historical Values for Inflation Indices Used in PBR Mechanisms

	Index			Handy-Whitman: Total Plant-All Steam-Pac. Coast Reg.[4]			SDG&E's Internal Cost Indices[5]	
Year	CPI[1]	GDP-IPD[2]	PPI-Electric Power[3]	1-Jan	1-Jul	Weighted Avg	Labor	NonLabor
1984	103.9	91	1.146	255	259	257	0.832	0.893
1985	107.6	94.4	1.158	258	258	259	0.881	0.917
1986	109.6	96.9	1.173	260	260	260	0.926	0.93
1987	113.6	100	1.217	259	262	264	0.963	0.952
1988	118.3	103.9	1.235	271	282	280	1	1
1989	124	108.5	1.229	288	293	293	1.038	1.048
1990	130.7	113.3	1.207	297	302	301	1.079	1.085
1991	136.2	117.7	1.204	303	309	306	1.128	1.12
1992	140.3	121.1	1.246	306	309	311	1.177	1.14

[1] Consumer Price Index-all goods-all urban consumers (Bureau of Economic Analysis)
[2] Gross domestic product, implicit price deflator (Bureau of Economic Analysis)
[3] Producer price index-electric power (Bureau of Labor Statistics)
[4] Handy-Whitman-all steam-Pacific Coast region (Handy-Whitman Bulletin No. 141, pp. 35-37.)
[5] San Diego Gas & Electric's internal cost indices (SDG&E)

Table B-6. Annual Change in DRI/McGraw-Hill Indices Used by PacifiCorp

Year	CPI	Rental Price	PPI-Coal	PPI-Non Energy Ind.	Weighted Avg.
1984	0.044	0.115	0.017	0.03	0.0708929
1985	0.035	-0.024	0	0.013	-0.0049297
1986	0.019	0.021	-0.014	0.009	0.0115912
1987	0.037	0.043	-0.036	0.027	0.0236092
1988	0.041	0.089	-0.018	0.053	0.0550298
1989	0.048	-0.002	0.001	0.042	0.0130392
1990	0.054	0.028	0.021	0.02	0.0284508
1991	0.042	-0.037	-0.003	0.016	-0.0104601
1992	0.03	-0.014	-0.023	0.013	-0.005229
Weights	0.1273	0.4905	0.1986	0.1836	

Source: DRI/McGraw-Hill *U.S. Review*, June 1995, pp.. 15, 61& 90 & unpublished DRI data provided by PacifiCorp.

Incentive Properties of a Hybrid Cap, and Long-Run Demand Elasticity

C.1 Overview

This appendix further addresses three issues raised in Volume I, Chapter 4: (1) the incentive effect of a hybrid price cap, (2) the probable values of the elasticity of long-run electricity demand, and (3) the derivation of profit-maximizing prices under price and revenue caps. Section C.2 focuses on the incentive to implement energy efficiency programs. This is analyzed for a hybrid cap composed of a mixture of a price cap and a revenue-per-customer cap. The results confirm Equation 4-11 of Volume I, Section 4.7. Section C.3 focuses on demand elasticity with particular emphasis on the empirical literature. Section C.4 derives optimal (to the firm) relative prices under price and revenue caps. This topic was initially discussed in Volume I, Section 4.9.

C.2 Incentives Under a Hybrid Price/Revenue-per-Customer Cap

The goal of this section is to evaluate the incentive to engage in effective energy-efficiency programs under a hybrid cap that combines a price cap with a revenue-per-customer cap. We begin by specifying such a cap.

The simplest hybrid revenue-per-customer cap uses a hybrid formula only on the energy component of costs and revenues. For the other components a simple rigid price cap is used. This may leave some minor problems with the incentive for load management, but generally, as was seen in Volume I, Section 4.5, the utility has an incentive towards effective load management even under a price cap. Thus the following simple form should be sufficient, though a more complex form would be needed if price flexibility were desirable.

$$P_N < \bar{P}_N, \qquad P_L < \bar{P}_L, \quad \text{and}$$
$$R_E < \bar{R}_N \cdot N - (\epsilon - 1) P_E \cdot m_0 \cdot q_0 \cdot N \qquad \textbf{(C-1)}$$

Where P_N is the price of access, P_L is the demand charge, R_E is the revenue from the energy charge, $\bar{R}$ is fixed, P_E is the price of energy, q_0 is initial energy use per customer, and N is the number of customers and is assumed fixed. The mixture of this hybrid cap is based on an elasticity of ϵ. The new variable, m, is the DSM control parameter. This actually modifies the meaning of q, so that $m \cdot q$ is now the true energy use per customer. The variable m_0 is the initial value of this variable. The variable m is needed because we wish to differentiate profit (π) with respect to m in order to evaluate the incentive to promote energy efficiency.

We will be interested only in the hybrid energy revenue cap, and until the end of our calculations we will not need to distinguish between the various constants that multiply P_E. Because we are dealing only with the energy part of the cap we will simply drop the subscript E from our notation. Also since N will be held constant in this calculation we replace $\bar{R}_N \cdot N$ with $\bar{R}$. With these simplifications we re-write the hybrid cap as follows.

$$R < \bar{R} - \alpha P, \qquad \text{where} \quad \alpha = (\epsilon - 1)\cdot m_0 \cdot q_0 \cdot N \tag{C-2}$$

We now write the definition of R, the energy component of revenue.

$$R = P\cdot m \cdot q(P)\cdot N \tag{C-3}$$

Note that we have now introduced the fact that energy use is a function of the price of energy. Because we omitted this fact in Section 4.5, we mis-estimated the power of revenue cap incentives in that section. Here we will correct that simplification. Substituting (3) into (2) and solving for $\bar{R}$ we have:

$$\bar{R} = P\cdot m\cdot q(P)\cdot N + \alpha P \tag{C-4}$$

Because the total differential of $\bar{R}$ is zero, we have:

$$(P\cdot m\cdot q' + m\cdot q + \alpha)dP + P\cdot q\cdot dm = 0\,. \tag{C-5}$$

Using the assumption that demand elasticity, $(dq/dP)(P/q)$, equals $-\eta$ allows us to find:

$$\frac{dP}{dm} = \frac{P}{(\eta - 1)m - \alpha/(q\cdot N)} \tag{C-6}$$

We now expand $\pi = R - C$, the definition of profit, to find:

$$\pi = \bar{R} - \alpha P - c\cdot m\cdot q(P)\cdot N \tag{C-7}$$

Differentiating this with respect to profit gives

$$\frac{d\pi}{dm} = -\alpha\frac{dP}{dm} - c\cdot N\cdot\left(q + m\frac{dq}{dP}\frac{dP}{dm}\right) \tag{C-8}$$

Substituting for dP/dm and dq/dP in equation (8) gives

$$\frac{d\pi}{dm} = \frac{-\alpha P}{(\eta - 1)m - \alpha/(q\cdot N)} - c\cdot N\cdot\left[q + m\cdot\left(-\eta\frac{q}{P}\right)\left(\frac{P}{(\eta - 1)m - \alpha/(q\cdot N)}\right)\right]. \tag{C-9}$$

This simplifies to

$$\frac{d\pi}{dm} = \frac{c\cdot N\cdot[m + \alpha/(q\cdot N)]q - \alpha P}{(\eta - 1)m - \alpha/(q\cdot N)}. \tag{C-10}$$

In the initial state of regulation, we have set $m_0 = m$, and $q_0 = q$, so we can make these substitutions now as we substitute for α in equation (10). This gives us

$$\frac{d\pi}{dm} = \frac{c \cdot N \cdot [m + (\epsilon - 1)m]q - (\epsilon - 1)m \cdot q \cdot N \cdot P}{(\eta - 1)m - (\epsilon - 1)m}. \tag{C-11}$$

This simplifies to

$$\frac{d\pi}{dm} = \frac{(\epsilon - 1)R - c \cdot N \cdot [\epsilon \cdot m]q}{(\epsilon - \eta)m}. \tag{C-12}$$

Note that the sign of both numerator and denominator have been reversed because the hybrid cap should be base on an elasticity, ϵ, that is greater than the actual elasticity of demand, η. So we may now assume that the denominator is positive. Note that c·m·q·N is just the cost © of producing energy. Thus

$$\frac{d\pi}{dm} < 0 \quad \text{if and only if} \quad (\epsilon - 1) \cdot R < \epsilon \cdot C \tag{C-13}$$

This indicates the utility will have an incentive to promote energy efficiency provided the revenue-cost inequality holds. If energy were priced at it's marginal cost this inequality would certainly hold. In the case of the example in section 4.5, R = 2 C, so with $\epsilon = 2$, as assumed in section 4.7 the inequality becomes an equality, and the utility is neutral towards energy efficiency.

As a final step we transform the hybrid cap from its revenue-cap form to its price-cap form. Solving equation C-1 for P yields:

$$P < \bar{P} - \frac{R}{(\epsilon - 1) \cdot m_0 \cdot q_0 \cdot N} \tag{C-14}$$

C.3 Evaluation of Long-Run Elasticities for Electricity Demand

Below, we consider two theoretical approaches to determining the long-run elasticity of electricity demand. First, the Averch-Johnson model is shown to predict elastic demand at equilibrium prices. Second, a model based on the assumption that the firm is optimally regulated (with full information) is shown to produce the same result. However challenges to both theoretical lines of reasoning exist and are put forward. This leads to section C.3.2 witch considers the empirical evidence.

B.3.1 Are Utilities Currently Operating in the Inelastic Portion of their Demand Curves?

As was demonstrated in Chapter 4, unless the utility is operating in the long-run inelastic portion of its demand curve, using a revenue cap is rather dicey business. In this section we investigate the question: is the typical utility facing a demand curve that is inelastic in the long run? We will not be able to make a definitive answer because both the theoretical and empirical literature is inconclusive. In particular we will find the following:

- The Averch-Johnson model predicts long-run elastic demand;
- Because standard cost of service (COS) regulation is not pure ROR, A-J may not apply;
- The empirical evidence is ambiguous; and
- The firm regulated for the social optimum does operate in the long-run inelastic region.

We begin with the Averch-Johnson model of rate-of-return (ROR) regulation. It assumes that at every instant the firm is forced to set its price so that it earns exactly some allowed rate of return R* on its invested capital. This allowed rate is over and above the cost of capital. A second, and less restrictive assumption, is also made: that the utility's output is an increasing function of both capital and labor.

The argument for demand elasticity under ROR proceeds by contradiction. Assume that demand is *inelastic* at the firm's equilibrium, so that a price increase (quantity decrease) increases revenue. The firm would decrease output by decreasing its labor input, thereby not changing its rate base or the amount of profit it is allowed. Decreasing labor decreases costs, while decreasing output allows a price increase that increases revenue (by the assumption of inelasticity). Thus revenue is increased while cost is decreased, so the net effect is an increase in profit. Thus the firm was not at equilibrium as assumed, which is a contradiction. This shows that the firm's equilibrium must be in the elastic region.

The above proof can best be understood through the following dynamic. As long as the firm is in the *inelastic* region of its demand curve it can increase revenue by cutting output. As long as it cuts output by cutting labor this will not affect it's allowed profit level, but will reduce costs. So it just keeps cutting output, and earning more revenue for less cost until output is so low that it finds itself in the elastic portion of the demand curve. If there is no inelastic portion, then the firm will continue to lower output and raise price without limit.

For a firm having a normal production function and under ideal ROR regulation, this argument is conclusive. However actual COS regulation is a bit more complex than pure ROR. First COS fixes prices periodically and lets actual return differ from allowed return during these periods. Second it maintains a standard of "used and useful" for all capital investments. This latter restriction is relevant in that it may, at some point, prevent the reduction of labor that was hypothesized in the above argument. If labor is reduce too far and output falls too much below what the capital is capable of producing, the regulator may find the capital no longer "used and useful." This may thwart the above described strategy of the firm to move to the elastic region of demand. We cannot say for sure that it will, because we do not know at what output level demand becomes long-run elastic.

B.3.2 Empirical Estimates of the Long-Run Elasticity of Electricity Demand

Since theory fails to answer this question we turn next to empirical work on demand elasticities. This summary of empirical work on demand elasticities is drawn from Chapter 7 of E. R. Berndt's *The Practice of Econometrics: Classic and Contemporary* (1991).

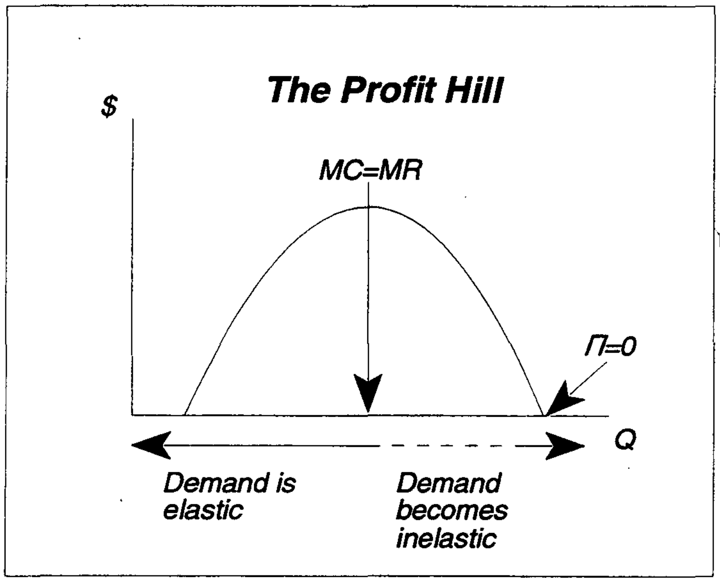
Econometric analysis of elasticities for electricity are complicated by several factors. Primary among these is the derived nature of the demand for electricity. Electricity is consumed not by people directly but by a stock of electric appliances. In the short-run, people can only vary their electric demand by changing their demand for the services these appliances provide. In the long-run, however, the stock of appliances can be changed. While this may not seem that complex, it does create a daunting data requirement. Franklin M. Fisher and Carl Kaysen, among the first analysts to tackle such a modeling approach directly concluded "to estimate [the stock of appliances] by states and years with any kind of reliability is simply out of the question."[6] To fully model the demand function, data on utilization of an existing stock at a given price is needed as well as data on the changes in the stock resulting from a given price. Furthermore, since choices of appliances as assumed to be based on expectations of future prices, consumers expectations about prices must be modeled. Alhtough Fisher and Kaysen did try to work around direct estimation, in the end they cautioned that "it is worth reiterating how poor our data really are."

Even when these data requirements can be worked around, the relationship between demand and the multi-part tariffs common in the electric industry makes the choice of price indicators nettlesome. The basic problem is that the amount a customer demand affects the price they are charged because of the multi-part tariffs and price affects demand because the downward slope of the demand curve. The question then arises whether to use the average price or the marginal price? Generally an average price can not adequately capture demand reaction under a complex rate-structure and so using it as a regressor can result in a serious bias. Using a single number for the marginal price, however, fails to capture changes in price that may induce a customer to change their demand such that they end up on a different tariff-block.

The complexity of choosing real world indicators aside, econometricians are always faced with a fundamental question of which functional form to use when simplifying the real world into a model. The most common to date largely because of it's simplicity is log-linear forms. The resulting constant elasticity of price and income from a simple model defies reality in the extremes. Adding layers of complexity can result in result in elasticities that vary with price

6 Quotations of Fisher and Kaysen are taken from Berndt (1991).

and income, but these risk running afoul of underlying economic theory. This has lead to interest in more flexible forms such as the translog and the generalized Leontief which of course come with their own host of complexities.



C-15Figure C-1.

Not surprisingly, the empirical estimates of long-run price elasticity of demand vary greatly based on the assumptions used. Efforts to directly include appliance stocks vary from 1.1 to 1.3 when average price is used as a regressor and from 0.4 to 0.7 when marginal price is used.[7] Indirect efforts that avoid using measures of the stock of appliances result in mean long-run elasticities of 0.8 when marginal price is used and 1.0 with average price is used.

Since the inelastic region of demand is represented by an elasticity value of 1.0 or greater, these numbers paint an ambiguous picture. On the whole though, they seem to suggest that firms are at best only producing slightly into the inelastic region of demand.

Only in the area of socially optimal theory can we find some certainty about what part of the demand curve the firm should be operating in. The easiest way to see why an optimally regulated firm will produce in the inelastic region of the demand curve is too look at a graph of profits against quantity. The profit curve takes the form of a hill. The top of this hill is the profit maximizing point where marginal revenue equal marginal cost. This is where a monopolist would choose to operate. We know that the inelastic region of the demand curve begins when marginal revenue equal zero, so we know that this region will start to the right of the peak of the hill. We also know that the optimally regulated firm will produce at the Pareto-optimal point where price equals marginal cost and profits are zero. This is the right most point on the profit hill. Putting what we know together, we can see that the optimally regulated firm will produce in the inelastic region of the demand curve. Figure C-1 depicts this intuitive proof (Train 1991).

7 We use the convention of showing demand elasticities as positive values.

C.4 Appendix to Section 4.9: Relative Prices Under Price and Revenue Caps

B.4.1 Relative Prices under a Price Cap

We begin by writing down the price-cap mechanism. Superscript 1 denotes this period while superscript 0 denotes last period. Both price, P, and quantity, Q, are vectors.

$$P^1 \cdot Q^0 \leq R^0$$

The firm maximizes profit, $\pi = R - C$ under the price-cap constraint, so we write down the Lagrangian for this maximization:

$$\mathcal{L} = P^1 Q^1 - C(Q^1) - \lambda \cdot (P^1 Q^0 - R^0)$$

We assume that cross elasticities are zero, and this allows us to differentiate each price with respect to its quantity. The partial of the Lagrangian with respect to each particular quantity equals zero.

$$\frac{\partial \mathcal{L}}{\partial Q_i^1} = \frac{dP_i^1}{dQ_i^1} Q_i^1 + P_i^1 - C_i^{/} - \lambda \frac{dP_i^1}{dQ_i^1} Q_i^0 = 0$$

Now divide through by P_i^1 and multiply the last term by Q/Q.

$$\frac{dP_i^1}{dQ_i^1} \frac{Q_i^1}{P_i^1} + \frac{P_i^1}{P_i^1} - \frac{C_i^{/}}{P_i^1} - \lambda \frac{dP_i^1}{dQ_i^1} \frac{Q_i^0}{P_i^1} \frac{Q_i^1}{Q_i^1} = 0$$

Now use the fact that elasticity, ϵ, is given by $-(dP/dQ)(Q/P)$.

$$-\frac{1}{\epsilon} + 1 - \frac{C_i^{/}}{P_i} + \frac{\lambda}{\epsilon} \frac{Q_i^0}{Q_i^1} = 0$$

Now substituting markup, μ, for $1 - MC/P$ and rearranging we have:

$$\mu_i = \frac{1}{\epsilon_i} \left(1 - \lambda \frac{Q_i^0}{Q_i^1} \right)$$

If Q^0 is now replaced by Q^1, and the firm re-optimizes, and this sequence is repeated the quantities will quickly converge to stable values. At this equilibrium we will have $Q^0 = Q^1$, which gives the result we were seeking and show in Volume I, Section 4.9, equation (4-14).

$$\mu_i = \frac{1 - \lambda}{\epsilon_i}$$

B.4.2 Relative Prices under a Revenue Cap

We begin by writing down the revenue-cap mechanism. Superscript 1 denotes this period while superscript 0 denotes last period. Both price, P, and quantity, Q, are vectors. Note that it differs from a price-cap mechanism in that the quantities are current, thus making the index being capped the current revenue and not just a fixed weighting of prices.

$$P^1 \cdot Q^1 \leq R^0$$

The firm maximizes profit, $\pi = R - C$ under the price-cap constraint, so we write down the Lagrangian for this maximization:

$$\mathcal{L} = P^1 Q^1 - C(Q^1) - \lambda \cdot (P^1 Q^1 - R^0)$$

We assume that cross elasticities are zero, and this allows us to differentiate each price with respect to its quantity. The partial of the Lagrangian with respect to each particular quantity equals zero.

$$\frac{\partial \mathcal{L}}{\partial Q_i^1} = \frac{dP_i^1}{dQ_i^1} Q_i^1 + P_i^1 - C_i^{\prime} - \lambda \left(\frac{dP_i^1}{dQ_i^1} Q_i^1 + P_i^1 \right) = 0$$

Now divide through by P_i^1.

$$\frac{dP_i^1}{dQ_i^1} \frac{Q_i^1}{P_i^1} + \frac{P_i^1}{P_i^1} - \frac{C_i^{\prime}}{P_i^1} - \lambda \left(\frac{dP_i^1}{dQ_i^1} \frac{Q_i^1}{P_i^1} + \frac{P_i^1}{P_i^1} \right) = 0$$

Now use the fact that elasticity, ϵ, is given by $-(dP/dQ)(Q/P)$.

$$-\frac{1}{\epsilon} + 1 - \frac{C_i^{\prime}}{P_i} + \frac{\lambda}{\epsilon} - \lambda = 0$$

Now substituting markup, μ, for $1 - MC/P$ and rearranging we have:

$$\mu_i = \frac{1 - \lambda}{\epsilon_i} + \lambda$$

which is the formula given in Volume I, Section 4.9, equation (4-16).

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