DISCUSSION PAPER

ON

Rate Regulation in Ontario

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September 2004

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List of Acronyms Used

ADR	Alternative Dispute Resolution
API	Actual Price Index
BCF	Billion Cubic Feet
BG	British Gas
Capex	Capital Expenses
CBM	Coal Bed Methane
CMP	Central Maine Power
CPI	Consumers Price Index
CPUC	California Public Utilities Commission
COS	Cost of Service
ERAM	Electric Revenue Adjustment Mechanism
ESM	Earnings Sharing Mechanism
FCC	Federal Communication Commission
FERC	Federal Energy Regulatory Commission
GDAR	Gas Distribution Access Rule
GDP	Gross Domestic Product
GDPPI	Gross Domestic Product Price Index
GLGT	Great Lakes Gas Transmission
HHI	Herfindahl-Hirschmann Index
IIP	Information and Incentives Project
KPI	Key Performance Index
LDC	Local Distribution Company
LDZ	Local Distribution Zones
LNG	Liquefied Natural Gas
MDPU	Massachusetts Department of Public Utilities
MMC	Monopolies and Mergers Commission
NEB	National Energy Board
NGF	Natural Gas Forum
NPV	Net Present Value
NTS	National Transmission System
O&M	Operations and Maintenance
OFFER	Office of Electricity Regulation
Ofgas	Office of Gas Supply
Ofgen	Office of Generation
Ofgem	Office of Gas & Electricity
Ofwat	Office of Water
Opex	Operating Expenses
ORA	Office of Ratepayer Advocates
PI	Price Index
PPCP	Public Party/Customer Proposal
PPI	Producer Price Index
PBR	Performance Based Regulation
OEB:	Ontario Energy Board
PES	Public Electric Suppliers

PEP	Performance Evaluation Plans
PCI	Price Cap Index
REC	Regional Electric Company
ROE	Return on Equity
RPI	Retail Price Index
SAIDI	System Average Interruptions Duration Index
SAIFI	System Average Interruptions Frequency Index
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SoCalGas	Southern California Gas Company
SOLR	Seller of Last Resort
SQI	Service Quality Indicator
TCF	Trillion Cubic Feet
TCPL	TransCanada Pipelines
TFP	Total Factor Productivity
TPBR	Targeted Performance Based Regulation
U.S.	United States
U.K.	United Kingdom
WACC	Weighted Average Cost of Capital

SECTION 1: Introduction

A. Overview

This Paper discusses past and present natural gas regulation in Ontario in conjunction with the Ontario Energy Board's (OEB) objectives and issues for the natural gas industry. These issues are: (1) gas pricing volatility; (2) different pricing mechanisms for a competitive natural gas market; (3) the utilities' role in gas supply; (4) storage regulation; and (5) regulation to provide utilities with incentives to provide high-quality natural gas services.

Natural gas markets involve several vertical components. These are: (1) production/commodity; (2) main line pipes; (3) storage; (4) distribution; (5) load balancing; (6) safety; (7) reliability; (8) metering; and (9) customer services. Both Cost of Service (COS) and Performance Based Regulation (PBR), have been and are still being applied to these various functions in different jurisdictions. In addition, components of these two different methodologies have been unbundled. Competitive markets, not regulatory bodies, determine prices and assign risks and rewards.

This analysis considers policies and facts that are projected to be about a decade out (more or less). During the next ten years, much of the natural gas restructuring that has taken place in North America, Canada, and Ontario are givens. For example:

- (i) Well-head price deregulation will not change;
- (ii) Pipelines will stay out of the merchant business and will not buy and resell system natural gas.
- (iii) Competitive markets for spot transactions will continue to expand and grow. Trading hubs will become more integrated.
- (iv) Vertical and actual physical/financial trading of pipeline shipping and storage rights will expand.
- (v) Choice for electricity producers and large natural gas users will continue to be available.

Despite the above list of likely "givens", there are many matters in play over the next ten years. The future composition of the natural gas industry in Ontario becomes much less clear. There are significant regulatory and competitive choices. These combine to raise several questions:

(i) Will local distribution companies (LDCs) open storage to direct retail customers? If they do so, will prices for storage be determined by markets or regulators?

(ii) Will LDCs retain system natural gas obligations? If so, will LDCs retain seller of last resort (SOLR) responsibility?

(iii) Will competitive retailers offer portfolios of natural gas supplies in the future, or will they continue to sell one-off fixed period contracts to retail consumers based on their various individual long-term natural gas contracts?

(iv) Will LDCs continue to provide load balancing and network reliability services as part of a bundled regulated tariff? Alternatively, will the LDCs unbundle their services with pricing determined by the market?

(v) Will network service pricing become *ex ante* and transparent, or will such services continued to be priced under regulation with few incentives for customers to internalize their network costs?

(vi) Depending upon the answers to the above questions, how will customer services, reliability, and metering be provided and regulated?

(vii) What is the future regulatory duty to protect retail customers?

(viii) Will competitive markets need monitoring, policing and modification? If so, who will be responsible?

(ix) How will alternate dispute resolution (ADR) and Codes of Conduct be facilitated and enforced?

(x) Will Ontario seek to expand the public goods attached to the natural gas industry such as conservation, renewable energy, public safety, and education? If yes, who will perform these functions and how will they recover their costs of service?

(xi) What is the future of natural gas for power generation in Ontario?

(xii) How will liquefied natural gas (LNG), MacKenzie Valley, Alaskan, and coal bed methane (CMB) natural gas come on line? How will risks, rewards, and prices be determined for Ontario's consumers?

These questions are not intended to present the total picture of the uncertainty facing Ontario. Rather, the list is intended to illustrate much of what is in play. That said, the questions and their potential answers, combined with the "givens", begin to shape the task at hand; to wit: what regulatory policy best fits the natural gas industry in Ontario over the next decade and what role would PBR best play?

The short, and perhaps most important, answer is that the shape, scale, and scope of the future natural gas market will define and establish the most sensible answers to most regulatory questions. This analysis seeks to provide scope and insight into these matters. The Paper's goal is to analyze these strong interdependencies to identify potential policy options, and not to determine definitively the "right" answer for Ontario.

Most of the attention is on the regulatory *status quo*, which reflects the current regulatory methods for the current industry structure and the natural gas services presently subject to the OEB's regulatory authority. This analysis will focus on system gas, network or ancillary services, and storage. This set of regulated services may be modified in light of structural reforms of the natural gas industry. In particular, changes in unbundling and competitive market policies for system gas and storage would have significant regulatory implications. We will discuss these ratemaking implications in the context of three potential end states, or packages, and will also address natural gas services that will remain regulated regardless of broader structural reforms: gas distribution itself and some related customer services.

This paper is organized as follows. This section discusses the current natural gas market structure and regulation in Ontario. Section Two is a conceptual discussion of regulatory tools that have been applied to natural gas services. It also summarizes COS and PBR alternatives and experience throughout the world related to both types of regulation. Section Three reviews regulation in Ontario. The Province's past regulatory successes and failures are discussed. Section Four reviews the salient regulatory issues addressed in the OEB's Natural Gas Forum (NGF). Section Five considers the regulatory implications that result from different choices and particularly considers system gas, network services and storage. Section 6 presents policy conclusions and evaluation criteria.

As explained, this Paper does not describe a preferred regulatory model for Ontario. The intention is to frame further discussion of these issues within the NGF, so that stakeholders have an informed basis for providing input and the OEB has an objective, well-defined framework for making decisions about the appropriate policy and regulatory approach.

This discussion streamlines the regulatory issues and options, relying on several appendices to provide greater detail and context. Regulatory reform is an inherently complex subject, made more so because of the myriad ways in which regulation and competitive market reforms can interact. This discussion focuses as closely as possible on the particular circumstances facing Ontario's natural gas industry, while at the same time drawing lessons from throughout the world where different regulatory approaches have been implemented. This detail and analysis are also found in Appendices to the report. Appendices One through Three present maps of storage and pipeline facilities in the region and service territories for Union Gas and Enbridge Gas, respectively. Appendix Four presents a more detailed analysis of the advantages and disadvantages associated with various PBR alternatives. Appendix Five is a survey of some of the main experiences with PBR, primarily in the U.S. and U.K.

B. Ontario's Current Situation

Ontario is a natural gas consuming province that imports natural gas from western Canada and the United States, primarily through TransCanada Pipeline's (TCPL) northern mainline route and through the Dawn Hub in Southwestern Ontario. TCPL's northern mainline route has a delivery capacity of about 3.6 billion cubic feet (BCF) per day. The Dawn Hub has a delivery capacity of approximately 3.4 BCF per day. Ontario consumes nearly 3 BCF of natural gas per day and nearly 1 trillion cubic feet (TCF) annually,[1] approximately thirty percent of the natural gas produced for domestic consumption in Canada.

1. One MCF equals 1.07 GJ.

Approximately 60 percent of the natural gas entering Ontario is moved across Ontario to Quebec, other eastern provinces, and to export markets in the Northeaster U.S.

The pipelines delivering natural gas into Ontario are: TCPL, Great Lakes Gas Transmission (GLGT),[2] Alliance, Vector, Panhandle Eastern, Tennessee, CNG Transmission, Texas Eastern, National Fuel Gas Supply, and Empire State. Ontario also has natural gas storage capabilities in the province totaling about 250 BCF. In addition, the Dawn Hub is interconnected with storage in the U. S., particularly in Michigan and at the Chicago Hub, which provides potential access to an additional 600 BCF of storage. (See Map 1 attached as Appendix 1).

Ontario has two major natural gas distribution companies. These are Union Gas (Union) (See Map 2 attached as Appendix 2) and Enbridge Gas Distribution (Enbridge) (See Map 3 attached as Appendix 3). Union has about 1.1 million retail customers and delivers approximately 525 BCF of natural gas annually. Enbridge has 1.7 million retail customers and delivers approximately 450 BCF of natural gas annually in Ontario. Smaller gas distributors in the province are NRG, Kitchener, Kingston and some other very small firms. The LDCs in Ontario supply about three fifths of all retail customers with system gas. This represents a little more than a third of the natural gas the LDCs deliver in Ontario.

By North American standards, Union and Enbridge are relatively large LDCs. Both are also affiliated with relatively large energy companies. Union is a subsidiary of Duke Energy.[3] Enbridge is a subsidiary of multi-national Enbridge.[4]

While both companies have mature natural gas distribution networks, they are also experiencing relatively rapid customer growth. For example, Enbridge has been

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2. TCPL owns 50% of GLGT.

3. Duke Energy also owns BC Pipeline & Field Services, Duke Energy Field Services, Duke Energy Americas, Duke Energy North America, DukeNet Communications, Crescent Resources, Duke Energy Gas Transmission, Duke Energy International, Duke Power, and TEPPCO Partners, LP

4. Enbridge owns interests in various liquids pipelines in Canada (Enbridge Pipelines, Inc., Enbridge Pipelines (NW), Enbridge Pipelines (Athabasca), Enbridge Saskatchewan) and the U.S. (Enbridge Pipelines (Toledo), CCPS, Frontier Pipeline, Mustang Pipe Line Partners, Chicap Pipe Line), interests in natural gas pipelines (Alliance and Vector), gas distribution (Noverco, Enbridge New Brunswick, AltaGas, and Inuvik Gas),, various customer services companies (Customer Works, NetThruPut, Tidal Energy), interests in emerging technologies (fuel cells and wind power), international pipelines (OCENSA and CLH), and Enbridge Technology.

recently been connecting about 50,000 new customers each year. Many gas distribution costs (*e.g.*, services, meters, and new distribution main) are driven largely by the number of customers served. It follows that the relatively rapid customer growth in the Province is putting upward pressure on gas distribution costs. Additional cost pressures are related to replacing fully depreciated gas distribution main, particularly main constructed from cast iron or bare steel. Unlike capital invested to serve new customers, capital replacement expenditures are not "funded" by additional revenues that result from expanding the customer base.

Changes in consumption patterns also affect the relationship between changes in revenues and changes in costs. In particular, for many natural gas distributors in North America, there has been a long-term trend of declining gas delivery volumes per customer. This pattern is particularly evident for residential customers. This is due, in part, to demand-side management programs and using more energy efficient appliances and insulation in new construction. Both factors tend to lead to less gas consumption on average per customer. Like most North American gas distributors, rate design in Ontario places more weight on volumetric than customer charges. Most gas distribution costs are driven by the number of customers served. The combination of increasing customer numbers, declining gas volumes per customer, and a volumetric-intensive rate design often leads revenue growth to lag cost growth. This creates pressure for gas distributors to seek rate relief and higher authorized returns on equity.

Natural gas deliveries to and across Ontario come under National Energy Board (NEB) regulation for Canadian pipeline resources and the Federal Energy Regulatory Commission (FERC) for United States pipeline resources. In the past, both nations have regulated inter-provincial and inter-state pipelines as full COS merchant pipelines. Over the past two decades or so, both nations have liberalized long distance natural gas pipeline regulation. This means that long distance pipelines are no longer natural gas merchants purchasing and reselling natural gas. Functions such as storage have also been somewhat unbundled.

At the state and provincial level, additional liberalization and unbundling has also occurred. Ontario has partially segregated the local or intra-provincial delivery or distribution of natural gas from the commodity or system gas business. This type of restructuring reflects upstream wellhead and inter-provincial pipeline restructuring down to, literally, the burner tip. In this extreme, retail natural gas consumers bid to purchase the commodity, or natural gas molecules, from highly liquid markets (*i.e.*, many sellers). Long distance pipelines deliver natural gas to Ontario to notational central delivery points. Union and Enbridge deliver natural gas throughout the province.

The OEB regulates this important final component of the supply chain down to the retail meter. Traditionally, the OEB applied a full COS regulation to LDCs that bundled natural gas purchase costs, storage, balancing services, and distribution (including meter reading, customer services, safety and reliability).

In 1987, the OEB began to restructure LDCsand in 1988, the OEB introduced consumer choice and allowed consumers to pick their natural gas supplier. Today, there is competition for the sale of natural gas to the retail consumers, side by side with regulation monopoly delivery function of the LDC. Ontario permits competitive companies, including LDC affiliate providers, to compete to provide unbundled natural gas commodity and reliability services to the retail market in Ontario. Other services remain regulated. Currently, the LDCs provide three important regulated services: (1) natural gas delivery; (2) system/network reliability; and (3) consumer metering, billing, customer service. Many of these services will remain regulated, regardless of developments in other natural gas markets because natural gas delivery is widely viewed as a "natural monopoly" service. A natural monopoly service has economies of scale where the cost of providing service to a territory is lower when service is provided by a single entity than if it is provided by any other possible combination of firms.[5]

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5. Natural monopolies arise when the economies of scale and economies of scope inherent in the production technology are realized at levels that are close to or beyond the size of the available market. These economies can arise for various reasons. One is that some economies are inherent in coordinating production. At least up to a certain point, there are often low incremental costs associated with planning and organizing the firm's activities. These unit costs therefore decline as output expands. "Pecuniary" scale economies can also arise from bulk purchasing of some inputs.

Another source of scale economies is the indivisibility of production inputs. Some inputs can be purchased "whole" only in certain sizes. These "lumpy" inputs include labor specialists. At smaller output levels, some component of these inputs may be underutilized. As output grows, more of these inputs are utilized and average cost tends to fall.

Energy distribution networks often also realize economies from growth in the number of customers served in a given geographical area. This is sometimes referred to as "economies of customer density."

Cost efficiencies can therefore be realized by having a single firm serve the market. However, because monopolies enjoy significant market power (particularly for essential services), they can set prices that lead to inefficient resource allocation and transfer available rents from consumers to producers. Regulating the terms on which monopolies provide service can lead to improvements in resource allocation, overall efficiency, and a more socially acceptable distribution of benefits.

One reason these economies arise is that inputs placed at a given location to provide service can provide the same service to nearby locations at low incremental cost.

SECTION 2: Utility Regulation Options and Experience

A. Criteria for Evaluating Various Regulatory Regimes

In appraising alternative approaches to rate regulation, it is useful to have clear evaluation criteria. This analysis assesses the different regulatory systems primarily on the basis of two fundamental criteria for evaluating regulatory systems, each with various sub-dimensions. The first is economic efficiency. The second is fairness.

1. Economic Efficiency

A regulatory system is economically efficient to the extent that it generates the maximum possible net economic benefits for society. In regulatory applications, economic efficiency has three important dimensions: (1) productive efficiency; (2) allocative efficiency; and (3) regulatory and transaction cost.

a. Productive Efficiency

Utility regulation encourages productive efficiency to the extent that it induces the subject utility to meet the demand for its products at minimum cost. In the short run, some inputs are "fixed" in the sense that adjustments in the amounts used are quite expensive (*e.g.*, automated meter reading equipment). Introducing such equipment may save cost over time, but it would not be cost effective to transform the entire metering system in one year. In the short run, productive efficiency depends on meeting demand with a minimum-cost mix of other, variable inputs. In the long run, all inputs are variable, and using capital equipment in a cost-effective manner is also a central efficiency concern. Productive efficiency, therefore, has a "static" component, reflecting the efficiency of variable operations and maintenance expenses, and a "dynamic" component reflecting the efficiency of capital investment choices.

b. Allocative Efficiency

Rate regulation encourages allocative efficiency to the extent that the service's value to the customers exceeds the (marginal) cost of providing service.[6] A company's

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6. Economists have used the term "allocative efficiency" in several ways. For example, allocative efficiency is sometimes defined so it includes using the optimal *mix* of production inputs for given levels of input prices, whereas productive efficiency pertains only to optimal input *levels*. There is little practical value in making this distinction and both types of decisions should be

success in achieving this goal depends on its product development and marketing operations. In the short run, adjusting rates for existing services to reflect changing market conditions is the main allocative efficiency challenge. In the long run, the mix of services offered by a company becomes an important concern.[7]

Product quality is another important aspect of allocative efficiency. Customers have varied needs for quality. Competitive markets typically respond to these needs by producing an array of competing products with different price-quality attributes. Allocative efficiency is improved as companies tailor their product mix to reflect heterogeneous customer demands, and willingness to pay, for quality. Competition between firms and consumers' ability to choose among alternatives is often sufficient to ensure that the quality of products available in the marketplace is appropriate.

The threat of lost business is weaker for utility companies than for the most competitive businesses where product quality is a vehicle for competition. The local utility is often a monopoly provider and stands to lose fewer sales than would a similar competitive firm if its service quality is off the mark. Since social benefits from regulation depend on both price and quality, encouraging appropriate quality levels is a proper regulatory objective.

c. Regulatory and Transaction Costs

Costs are incurred in utility regulation. These include the resources (*e.g.* accountants, lawyers, and hearing rooms) of utilities, interveners, and government agencies dedicated to the regulatory process. Senior company officials and operations supervisors are also drawn into the regulatory arena. This can divert employees' attention from their main responsibilities and performance may suffer as a result. While reducing regulatory cost is not an end in itself, regulation is more efficient to the extent that it is not needlessly costly.

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included in the productive efficiency criterion. Allocative efficiency applies to choices leading to an optimal allocation of goods in the marketplace given consumer demands and, therefore, applies to marketing as opposed to production decisions.

7. The allocative efficiency of a company's operations does not depend solely on "core" services offered to customers without competitive options. Companies may also be able to enhance societal benefits or welfare by meeting demands in more competitive markets. Involvement in competitive markets can spread the cost of inputs used to provide monopoly services across more output, thereby reducing unit costs for the products provided by the company. Competitive market involvement can also potentially increase the number and variety of products available to customers in these markets.

Customers also incur transactions costs by spending time and money gathering information, making choices, and completing transactions. Transaction costs are also relevant when change causes consumers to make choices that regulation previously bundled into basic services. For smaller volume users, these costs could be a burden that outweighs the benefits that pro-competitive changes can generate in terms of cost and price reductions.

2. Fairness

A second fundamental criterion for appraising regulatory systems is fairness. Fairness means the manner in which social benefits are divided among the stakeholders in the regulatory process. Customers and shareholders are the primary stakeholder groups. However, the manner in which net benefits are divided among the stakeholders (*i.e.,* residential, industrial, and other customer sub-groups) is also important.

Economic analysis can assess the net social benefits and distribution effects associated with alternative regulatory systems. Different regulatory systems can only be ranked by distributional outcomes if weights are applied to the welfare of different stakeholder groups. Since there is no objective basis for assigning these weights, economists have, to date, focused mainly on the efficiency of alternative regulatory systems.

However, regulators are not "ivory tower" economists and must consider the effect their decisions would have on various stakeholders. How to distribute the benefits that result from policy changes is an important regulatory concern. Treating "equals" the same and avoiding undue cross subsidies are also important fairness objectives. These concepts can assist regulators in analyzing policy changes that may cause some customers to pay less but lead to benefits for all customers.

The fairness of the regulatory process itself is also relevant. Regulation is perceived to be fairer as it becomes more open to input from all parties. Regulatory outcomes are also likely to be viewed as more fair as the basis for decisions becomes more transparent and verifiable by outside parties. At the same time, making regulation more open, consultative and transparent tends to raise regulatory costs. Optimizing the tradeoff between the fairness of the regulatory process and the resulting regulatory costs is ultimately a matter of judgment. Below, we review COS regulation and PBR through the twin prisms of efficiency and fairness.

B Cost of Service Regulation

COS regulation is the traditional method used to regulate investor-owned utilities in North America.[8] Under this system, the rates approved by a regulatory board or commission are expected to recover the company's prudently incurred cost of providing regulated services. This cost includes a return on capital.[9] Rate cases are held occasionally in which estimates are made of the prudent cost of capital, labor, and other inputs used to provide regulated services. The volatility of energy prices has prompted some regulators to provide for a shorter lag between purchasing energy inputs and adding these costs to the revenue requirement.[10] As discussed below, Ontario has followed this approach. The basic steps in COS regulation are: (1) establishing the utility's revenue requirement (*i.e.*, its prudently incurred cost of service); (2) projecting the utility's sales volumes; and (3) designing tariffs to collect the utility's revenue requirements from its customers.

Determining the revenue requirement and allocating that revenue requirement among customer groups is often contentious and resource intensive. These tasks are often made more difficult when the utility has common costs incurred jointly in providing various services. The inherently arbitrary nature of common cost allocations makes them controversial in COS regulation.

In many instances, COS regulation works reasonably well. North America has constructed the world's largest and most reliable energy delivery network via regulated entities operating under COS methods. When COS regulation works properly, it

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8. The term "utility" is defined here and throughout the Green Paper as an enterprise that provides essential services on a monopoly basis and, if private, is subject to rate and service regulation. As such, the term encompasses oil and gas transmission companies, electric utilities, and gas distributors.

9. This characterization of COS regulation is stylized. The terminology and precise procedure for setting rates varies considerably across regulated industries and regulatory jurisdictions.

10. When a utility company also sells some products in unregulated markets, it becomes even more complicated to accurately determine costs. Almost every utility has some involvement in such markets. Consider, for example, a utility that rents out its under-utilized real estate. To the extent a utility has such operations, its total cost will exceed the cost of regulated services and some share must be assigned to the regulated services.

provides strong signals for utilities to build new infrastructure and consumers receive safe and reliable services.

There are instances where COS has broken down. For example, when there are either sudden or persistent upward pressures on the prudent cost of providing utility services, the slow, resource intensive nature of COS regulation can make it difficult to respond in a timely way. When utility systems are shocked by outside forces such as a world oil crisis, double digit inflation and interest rates, or economic recession, stakeholders are often especially unhappy with the results.

COS regulation is often criticized for failing to achieve the maximum possible net benefits for society. This parallels the critique that economists have made about the merits of competition and regulation for contestable, but traditionally regulated, utility services. When services are not characterized by natural monopoly conditions, competition is feasible and preferable to regulation. For natural monopoly services, the regulatory system should attempt to harness and replicate the same incentives for efficient performance that exist in competitive markets. COS regulation often fails to create these incentives.

Part of the problem is the high cost that must be incurred for regulators to fully understand a utility's operations. If they knew the efficient way to produce and market utility services, regulators could simply set prices to recover the minimum cost of providing the optimal array of utility services. Unfortunately, it is often difficult even for utility company managers to recognize best practices given the substantial uncertainty that exists regarding future supply, demand, and policy conditions. The challenge is much greater for regulators since they are apt to have little direct experience with utility operations. This results in "information asymmetry." Redressing the informational asymmetry between company managers and regulators requires substantial data exchange, processing, and analysis, a process that is both time consuming, costly, and often inefficient.

Some measures can be taken to contain these regulatory costs. For example, rate cases may occur at less than annual intervals. Extending the period between rate cases is known as "regulatory lag." The potential for regulatory lag is also limited for most energy utilities. Prices of some utility inputs, like natural gas, are volatile.

Failing to adjust rates for changes in the cost of these inputs would make earnings volatile, thereby raising the cost of capital. Regulatory lag is further constrained since prices in most utility industries trend upward to compensate utilities for unavoidable input price inflation. Infrequent rate cases become even less tenable when there is rapid industry change or when companies want to modify their rate structures and service offerings in response to changing market conditions. The end result is that rate case cycles in utility industries typically do not exceed three years, and annual rate cases are common. Regulatory lag is especially short for energy procurement activities.

Regulatory costs can be contained by limiting the scope of prudence reviews, which tend to be asymmetrical in that actions found to be imprudent will be punished while actions that either are fortuitous or are judged exemplary are not rewarded., and basing new rates more on the company's reported costs than on external unit cost standards. It is rare for regulators to reward utilities with superior performance at COS reviews. Consequently, firms are not explicitly encouraged to undertake initiatives designed to improve performance.

Regulatory cost can also be contained by restricting practices that complicate regulation. For example, service offerings could be limited and rate structures kept simple. Companies could be discouraged from engaging in novel activities. Such simplifications may reduce regulatory costs, but can also diminish productive and allocative efficiency. If price adjustments are based on the trend in the company's own unit cost, efforts to trim costs or improve the market responsiveness of rates and services would lead, eventually, to lower rates. This weakens company incentives to improve cost performance. Incentives would be especially weak for initiatives that require upfront costs to achieve long-term benefits.

Restrictions on utility operations can also reduce efficiency. Limited service offerings and inflexible rates hamper the utility's ability to satisfy its customers' complex and changing needs. The efficiency losses from ineffective marketing are especially acute where demand is elastic. These are likely for customers with competitive access, including the ability to shift activities to sites served by other utilities, and for incremental consumption of utility services as well as economically distressed customers. Unresponsive market offerings can also lead to uneconomic bypass of the company's services. More typically, margins from services to markets with high demand elasticity will not be maximized, so that a larger share of the utility's cost must be recovered from other customers whose demand is relatively inelastic.

In summary, there is a tradeoff in COS regulation between productive and allocative efficiency and the cost of regulation. Maximum productive and allocative efficiency can be achieved, but at a high regulatory cost. Most practical efforts to contain these costs create inefficiencies and will invite time and resource consuming regulatory controversies.

C. Performance Based Ratemaking

1. Overview

PBR is both an alternative form and enhancement of traditional COS regulation. In North America, PBR plans have been approved in Alberta, California, Florida, Illinois, Maine, and Ontario. The FERC and NEB use PBR to regulate oil pipelines and some gas lines. The FERC has recently encouraged using PBR to regulate electric power transmission. Outside North America, regulators starting with a "clean sheet of paper" have generally chosen PBR instead of COS regulation, so that PBR is now the standard form of energy utility regulation in the world. PBR is also extensively used in other regulated industries, most notably telecommunications.

PBR is intended to deliver greater benefits to customers even as it reduces regulatory costs. The main idea behind PBR is to establish rules that create inherent incentives for utilities to meet desired regulatory objectives. A well-designed PBR plan will create market-like incentives for the utility to operate in an efficient and effective manner for the customers' benefit, reducing the need for continuous and detailed regulatory scrutiny of utility operations. It is essential that a PBR plan have a set of well-defined regulatory rules that promote efficient behavior.

Efficiency is promoted by weakening the link between a utility's prices and its unit cost of service. To the extent that this goal is met, it is possible to attain higher levels of productive and allocative efficiency at a lower regulatory cost level. A well designed PBR plan can increase earnings, lower prices, and improve service terms.

PBR accomplishes this in several ways. First, PBR uses automatic rate adjustment mechanisms established prior to their implementation. Such mechanisms are often represented by mathematical formulas. Using such mechanisms can reduce both the frequency and scope of regulatory intervention.

Second, the PBR mechanisms rely heavily on external data that are not sensitive to actions taken by utility managers. Examples include input price and productivity trends of other utilities. When rate adjustments are based on external data and automatic adjustment mechanisms, the regulatory system is externalized and utilities can be more confident that unit cost reductions will not be translated too quickly into price reductions. Greater certainty that shareholders will retain the benefits of unit cost reductions for some reasonable period strengthens performance incentives, in turn promoting productive and allocative efficiency.

PBR is also grounded in economic research. Theoretical and empirical research can be used to analyze appropriate combinations of automatic mechanisms and external data. For example, PBR tools can help design a regulatory system that protects utilities from unavoidable input price fluctuations while simultaneously ensuring that customers receive the benefit of "normal" performance improvements.

The end result is a regulatory process that makes allowed prices less sensitive to company actions, thereby strengthening incentives and enhancing operating flexibility. The potential benefits from rate regulation are therefore increased. PBR plans can be designed so these additional benefits are shared between shareholders and customers.

2. Taxonomy

Various mechanisms can be used to craft PBR plans. The basic approaches to PBR include price caps, revenue caps, and benchmark-based mechanisms. Earnings sharing mechanisms (ESMs) are often included with the structure of the three PBR forms discussed here, although they are sometimes considered to be a separate PBR form.

Appendix Four contains a detailed discussion of various PBR options, along with the pros and cons of each. The primary aspects are as follows:

Price or Rate caps are the most common form of PBR in the world today. The simplest rate cap approach holds prices constant for the plan's duration. This is sometimes called a rate freeze or moratorium. Another rate cap approach limits price adjustments using indexes. Growth in allowed prices is limited using a price cap index

(PCI).[11] While the formulas vary from plan to plan, it is generally true that the price changes (ΔPCI) are based on the difference between an inflation factor (*P*) and a productivity, or X-factor (*X*), that reflects projected cost savings and/or sales growth, plus or minus a Z-factor (Z), which is intended to promote a particular public purpose (*e.g.*, conservation, reliability, etc.).[12] The standard rate cap formula is:

$$\Delta PCI = P - X \pm Z.$$

Revenue caps are similar in many respects to price or rate caps, except revenues rather than utility prices are subject to restrictions and adjustments. Revenue caps can take the form of either freezes/moratoria or formula-based revenue adjustments. Such indexing formulas commonly include terms for customer or sales growth.

Benchmark regulation involves evaluating one or more performance indicators or metrics of utility activity using external performance standards (benchmarks). The standards are external to the extent that the comparison metrics are insensitive to the actions taken by the subject utility's managers. A benchmark plan's key features are the performance indicators, the performance benchmarks, and the penalty/reward adjustment mechanism. Benchmark regulation plans can be targeted at specific activities, such as service quality, or more comprehensively, such as the unit cost of service.

Earnings sharing mechanisms (ESMs) are another form of PBR. It is, however, more common for earnings sharing to be a component in a broader PBR reform package. An ESM leads to automatic rate adjustments according to preset formulas that compare a company's actual and allowed earnings. The earnings measure is typically return on equity (ROE). Typically, the differences between actual and allowed ROE are shared between customers and shareholders according to formulae spelled out in the ESM approach. Typically, ESM bands change the sharing percentages between customers and shareholders as earnings move away from the preset norm.

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11. The acronyms API and PCI were developed in U.S. Federal Communications Commission (FCC) proceedings.

12. The term Z-factor was developed in the FCC proceeding to develop a price cap plan for AT&T. It was so called because the PCI for AT&T had also included an "X" factor and a "Y" factor to affect a specific category of price cap adjustments.

3. Experience

PBR has been relatively popular and a full review of PBR is quite voluminous. Appendix Four contains a more detailed description of PBR. Appendix Five reviews PBR experience using a broad sample of PBR plans from North America and the U.K. Here, the discussion will focus on the most relevant aspects of this PBR experience from the point of view of Ontario's natural gas industry. Six factors are most salient. These six factors are: (1) PBR plans, once implemented, have almost always been retained; (2) sharing benefits with customers is crucial to a plan's success; (3) comprehensive and targeted PBR plans have been approved; (4) PBR proceedings often involve technical issues such as estimating industry productivity trends; (5) there is often an issue as to whether an "inflation differential" term is needed in index-based PBR plans; and (6) revenue stability is becoming an important issue. We discuss each of these factors in greater detail below.

First, although PBR has often been modified, it has almost always been retained. This is most obviously the case in the U.K., which first implemented "RPI – X" regulation for British Telecom in 1984 and has since expanded this regulatory approach to privatized gas, electric, water, and rail services. There have been multiple updates of PBR plans for these regulated entities, and there has been no serious attempt to abandon this approach in favor of COS regulation. The U.S. has a shorter PBR history, but again the bulk of the experience shows that PBR has been retained where it has been implemented. Prominent PBR practitioners include San Diego Gas and Electric (SDG&E) (subject to a "third generation" PBR plan that is currently being reviewed and updated for a likely fourth generation) and Mississippi Power (which has been subject to a series of benchmark-based Performance Evaluation Plans (PEPs) since 1986).

Second, sharing PBR benefits with utility customers has always been critical for successful PBR plans. Controversy over benefit distribution can be reduced by establishing explicit benefit-sharing provisions at the plan's outset. If this does not occur, benefit-sharing issues are simply deferred until the plan is updated. The U.K. did not explicitly incorporate benefit-sharing mechanisms in its initial PBR plans, so the initial update of these plans were largely cost-based reviews that transferred to customers the cost savings that were achieved during the initial plan. Benefit sharing is usually critical for gaining initial approval of PBR plans in the U.S., so these plans often contain more explicit benefit-sharing provisions than do plans overseas.

Third, both comprehensive and targeted PBR plans have been approved. For utility rate regulation, however, there are many more examples of comprehensive PBR plans that apply index-based adjustments to either overall rates or revenues rather than, say, O&M costs. Targeted PBR plans have more frequently focused on auxiliary regulatory objectives, particularly maintaining appropriate service quality.

Fourth, PBR proceedings often involve technical issues such as estimating industry productivity trends. These issues are often unfamiliar to stakeholders and regulatory agency staff. Regulators typically must evaluate these issues by weighing technical, and competing, evidence presented by outside experts. Although one might expect different regulators evaluating unfamiliar productivity evidence to reach significantly different conclusions, there has been a remarkable degree of consensus among regulators in different jurisdictions and at different times on the appropriate values for key PBR parameters. Table 1 shows the industry total factor productivity (TFP) and stretch factors approved in the eleven comprehensive indexing plans for which North American regulators made specific findings on these elements.

Table 1

Company	Jurisdiction	TFP	Stretch	TFP + Stretch
PacifiCorp	California	1.4%	0%	1.4%
PacifiCorp-update	California	1.5%	0%	1.5%
Southern California Edison	California	0.9%	0.56%	1.46%
Southern California Gas	California	0.5%	0.8%	1.3%
SDG&E– Gas	California	0.68%	0.55%	1.23%
SDG&E-Electric	California	0.92%	0.55%	1.47%
Boston Gas	Massachusetts	0.4%	0.5%	0.9%
Boston Gas-update	Massachusetts	0.56%	0.3%	0.86%
Berkshire Gas	Massachusetts	0.4%	1.0%	1.4%
Ontario power distributors	Ontario	1.25%	0.25%	1.5%
Union Gas	Ontario	0.9%	0.5%	1.4%
Average		**0.86%**	**0.46%**	**1.31%**

This experience reflects the terms of PBR plans approved for a mix of jurisdictions, industries (*e.g.* bundled electricity services, electricity distribution, and natural gas distribution), and time periods. TFP measures have also been computed for the companies themselves (*e.g.*, PacifiCorp, SCE), nationwide industries (*e.g.*, Southern California Gas Company [SoCalGas], SDG&E), regional industries (*e.g.*, Boston Gas and Berkshire Gas), and the industry in a single Canadian Province (Ontario electricity distribution). Both the TFP trend and stretch factors in these plans typically are within a relatively narrow range. The authorized range for the sum of the TFP trend and the stretch factor is even narrower. While this is a small sample, it represents most of the indexing plans used in North America for energy utilities.

Overall, this experience has been positive. There has been a high degree of convergence among approved TFP trends in different plans. There has also been great similarity in the consumer sharing allocation. These have essentially reflected a common regulatory judgment.[13] This experience suggests, at least to date, there is little evidence to support the view (advanced by some Ontario stakeholders) that North American regulators will reach arbitrary and unfounded decisions on PBR parameters by failing to properly evaluate technical evidence.

13. The largest consumer dividend, for Berkshire Gas, also reflects expected merger savings, and this plan did not include an earnings sharing mechanism.

Fifth, there is an issue in index-based PBR as to whether an “inflation differential” term is needed for the selected inflation measure to track the industry input price trend accurately. Table 2 shows the input price differentials in the eleven approved indexing plans in North America. An “N/A” means that this element was not applicable to the plan since the indexing formula used an industry-specific inflation measure.

Table 2

Company	**Jurisdiction**	**Input Price Differentials**
PacifiCorp	California	N/A
PacifiCorp-update	California	N/A
SCE	California	0
SoCalGas	California	N/A
SDG&E– Gas	California	N/A
SDG&E-Electric	California	N/A
Boston Gas	Massachusetts	-0.1%
Boston Gas-update	Massachusetts	0.3
Berkshire Gas	Massachusetts	-0.1%
Ontario electricity distributors	Ontario	N/A
Union Gas	Ontario	1.1%
Average		**0.24%**

Six of these eleven plans (including Ontario’s electricity distributors) have avoided the input price differential issue by using industry-specific inflation measures. Two jurisdictions, Massachusetts and Ontario, have adjusted utility input costs relative to their estimates of specific utility cost structures and circumstances. Massachusetts uses an input price differential in its plan, but this is relatively small. The Union Gas plan in Ontario used a relatively high percentage adjustment for utility costs, at a plus 1.1%. This matter is addressed below.

Sixth, the issue of revenue stability is beginning to receive more attention in ratemaking mechanisms. For example, in California, SDGE’s PBR indexing mechanism has changed from price indexing to revenue indexing mechanisms. Revenue stabilization mechanisms have also been approved for other natural gas utilities, in part due to the secular industry decline in the volumes sold per customer.

Revenue indexing mechanisms have also been preferred to price indexing in Oregon and British Columbia where energy conservation has been a public policy priority.

SECTION 3: Ontario's Recent Regulatory Experience

Ontario's natural gas distributors were traditionally regulated using COS methods. Both major gas distributors in the Province recently adopted PBR plans. However, at the plans' termination, the OEB requested that the companies file a new COS filing to set new benchmarks and a new PBR proposal. However, both companies chose not to update their PBR plans when they expired and instead filed only traditional COS cases. As discussed earlier, this is contrary to most jurisdictions' PBR experience.

In evaluating Ontario's regulatory experience, the PEG/ICF/Exel team solicited input from a wide array of stakeholder groups. These groups included the two largest natural gas LDCs. Most stakeholders expressed support for the concept of PBR. This support partly reflected acknowledged flaws in the COS regulatory model (*e.g.* high regulatory costs, relatively weak incentives to perform efficiently and to be innovative, etc.). But while nearly all stakeholders agreed that there could be benefits with PBR in principle, they also expressed dissatisfaction with how PBR for LDCs worked in Ontario.

The three recent PBR experiences in Ontario are the obvious starting point in the analysis. The first PBR approach used in Ontario is the price indexing plan approved for electricity distributors. The second PBR approach is the partial indexing plan for the operations and maintenance (O&M) expenses of Consumers (now Enbridge) Gas. The third PBR approach is the comprehensive price indexing plan approved for Union Gas.

A. Electric Power Distributors in Ontario

Ontario implemented comprehensive PBR for the Province's electric power distributors in 2000. This PBR plan evolved from an OEB-sponsored, Province-wide consideration of regulatory issues that had a focus similar to that of the NGF. Expert opinion and discussion helped to guide the process and to synthesize inputs from various stakeholders. Industry task forces worked with Board staff to produce a proposed rate handbook for electricity distribution for designing PBR plans for electric power distributors. This proposed handbook was issued for broad consultation and subsequent to the consultation process; the OEB approved the Electricity Distribution Rate Handbook (Handbook) in early 2000.

The OEB approved PBR for electric power distributors and found that "PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation." The fundamental policy forged incentives that more closely resembled those in a competitive market. The purpose was to make regulated electric utilities responsible for their investments subject to price cap constraints.

The OEB also approved an industry-specific inflation measure for the electric power distributors. However, to reduce potential price volatility under the plan, it only allowed one-half of the change of capital input prices to be passed through in retail prices in a given year. While the proposed handbook recommended an innovative "menu approach" towards selecting the X factor. There was a menu of six alternative X factor and earnings sharing factor combinations. The lower values for the X-factor were associated with higher earnings sharing levels for consumers and *vice versa*. Utilities were then supposed to select the X factor-earnings sharing combination that most appealed to their risk-incentive preferences. Following industry input in the consultation process, the OEB subsequently determined that this approach was too complex for a first generation PBR plan. It also did not believe that there was a well-developed analytical foundation supporting the specific menu of X factor and ROE combinations. Instead, the OEB selected a single X factor of 1.5%, which was equal to a 1.25% TFP trend estimated for the Province's power distribution industry and a 0.25% stretch factor. It also imposed a single ESM, with 50/50 sharing above the allowed ROE.

The OEB also determined that providing distributors with some flexibility to determine how rate increases allowed under the plan would be allocated across rate classes, even though such flexibility would have been controlled by specific conditions on allowed rate changes. The proposed handbook explained that this would allow utilities to gradually implement more cost-reflective pricing over the plan's term. The OEB determined that is was not clear how such pricing flexibility could be implemented under the plan. The OEB also concluded that such flexibility could lead to greater relative price changes for customers with the least price-elastic demand for service.

The electric PBR plan also did not implement penalties or rewards for service quality performance, as has been common in other jurisdictions. Instead, the plan established a data collection, reporting and monitoring system for six customer service indicators and three reliability indicators.

The electric PBR plan was set to run for a three-year term, from 2000 to 2002. Before the plan could run its course, the Provincial government imposed a freeze on overall retail electric prices. This cap effectively eliminated any formula-based retail price adjustments for electric distribution services.

B. Enbridge

In 1999, the OEB approved a targeted performance based regulation (TPBR) plan for the Consumer's Gas (Enbridge) O&M expenses. At the time, the OEB described this as an important step on the transition to comprehensive PBR. The TPBR plan adjusted Enbridge's O&M costs using an indexing formula. The inflation factor in the formula was the Ontario Consumers Price Index (CPI), although the OEB said that, in principle, it supported using industry-specific inflation measures. The X factor of 1.1%, was equal to the 0.63% partial productivity growth trend proposed by Enbridge plus a stretch factor of 0.47%. The PBR plan did not have an ESM or any other explicit customer benefit sharing provisions. The PBR plan had a three year term, running from 2000-2002.

The TPBR generated a considerable amount of controversy, and when the plan expired, Enbridge did not present an updated PBR proposal. Perhaps the most controversial issue was that Enbridge changed its operations significantly while the TPBR was in effect and began outsourcing several O&M services from newly-established unregulated affiliates. Without an ESM, the plan did not generate any explicit, tangible benefits for retail customers. After the TPBR terminated, Enbridge filed a series of one-year, traditional COS rate cases.

3. Union

In 2001, the OEB approved a price indexing PBR plan for Union's gas storage and delivery services. Union had proposed a CPI-X indexing plan with an X factor of minus 0.3%, which would have led to regulated prices rising more rapidly than the rate of CPI inflation. Union's proposed X factor was comprised of a minus 0.4% TFP trend for the Company's southern operations less a 0.3% economy-wide TFP trend, plus a 0.4% stretch factor. This effectively would have been the negative economy-wide trend. The inflation factor was the GDP-PI. Union's proposal did not include a retail customer

ESM, but did propose pricing flexibility within two separate baskets of services. Union also recommended that the PBR plan should be maintained after the plan's proposed five-year initial term, with the update focusing only on adjusting the parameters of the PBR formula rather than resetting regulated prices or shared benefits based on a COS filing. This would have meant any savings stayed in the LDC.

The OEB approved a price indexing plan for Union with much different terms than Union had proposed. The approved X factor was equal to 2.5% and was comprised of a 0.9% productivity trend, plus a 0.5% stretch factor, and an input price differential of 1.1%. This OEB plan meant that inflation would have to exceed by 2.5% before retail rates would increase. The OEB relied on a range of TFP measures proposed by intervenors when deciding on the productivity trend and stretch factor. These productivity studies were generally higher than those Union presented due to the weight placed on gas volumes, not customers, in the TFP trend measures. Volumes per customer have recently been declining in the Province, so all else equal, placing greater weight on volumes, not customers, reduces the measured TFP growth.

For the input price differential, the OEB relied on Union's evidence showing that its input prices were growing 1.1% less rapidly on average than the GDP-PI. The OEB concluded that such an input price differential was necessary for the PBR plan to reflect the expected input price inflation of the industry. The OEB determined that Union's pricing flexibility proposal was not needed and added an ESM to the plan, with 50/50 sharing of earnings outside a deadband of +/- 100 basis points around the allowed ROE.

The plan's term was three years, from 2001 to 2003. The OEB refused to limit the scope of factors it might consider when updating the PBR update, but said it would expect such an update to include a COS study as well as an industry-wide TFP study that included separate TFP trend measures for gas transmission, storage, and distribution. When the plan expired, Union did not present an updated PBR proposal, but rather filed a traditional cost of service case.

4. Evaluation

There are some signs of success under Ontario's gas PBR plans. For example, Enbridge has undertaken a series of reforms designed to boost productivity. It has also implemented an employee bonus system where employee compensation is tied to achieving company-wide, divisional, and employee-specific performance on key performance indicators (KPIs). However, it is not clear to what extent these initiatives can be attributed to PBR *per se,* since some of these initiatives appear to predate Enbridge's TPBR while others have been continued after Enbridge returned to COS regulation.

At the same time, parties expressed far more concern about how PBR has been implemented in the Province. The LDCs pointed to continued high reporting and other regulatory costs under PBR and what they believed were, at times, arbitrary regulatory choices for the parameters of PBR plans. The most common complaints among intervenor groups were the absence of any explicit or tangible benefits resulting from the PBR plan and the change in the structure of Enbridge operations during the time its PBR plan was operating.

Both LDCs and several interevenor groups also agreed that developing PBR in the Province has been hampered by the OEB's perceived lack of leadership on the issue. These groups think that greater understanding and consensus on PBR is likely to be developed if the OEB takes a more prominent role in articulating its views regarding the purpose, application, and most appropriate design of PBR plans.

Further support for this conclusion is evident when one examines differences in how PBR has been implemented for Ontario's gas and electric industries. In electricity, the OEB took an active, leading role in evaluating PBR options and working with stakeholders towards a preferred PBR model. Ontario also has many more electric power distributors than natural gas distributors. Many of the electric distributors are small, urban firms that do not have the resources or expertise to develop detailed PBR models on their own. Consequently, the OEB had to take a more active role in developing a PBR framework that was applicable to the industry as a whole.

The OEB was also motivated to develop a workable, Province-wide PBR model in order to minimize the regulatory costs that would be associated with dealing with hundreds of COS rate cases for individual utilities. The premature suspension of the electricity PBR plan makes it impossible to judge how well it worked in practice. Nevertheless, the process produced a comprehensive, rigorous review of the most relevant PBR design issues and a well-developed conceptual framework (the Handbook) for developing PBR plans. In contrast, the natural gas LDC PBR plans have been developed in a more *ad hoc* fashion based on initial company proposals with subsequent intervenor input and OEB analysis and regulatory decisions.

Beyond the OEB's role, comparing PBR experience in Ontario with the experience elsewhere highlights several other factors which are analogous to the factors we discussed earlier, that have limited PBR's effectiveness in the Province. These factors are: (1) the attention devoted to benefit or earnings sharing between rate payers and owners; (2) the term of the plan; (3) whether the plan is targeted or comprehensive; (4) the need for technical input; and (5) choosing the appropriate inflation measure.

The first factor is the attention devoted to benefit-sharing between ratepayers and owners. The Enbridge plan, in particular, did not contain explicit provisions to share benefits with customers. This shortcoming contributed to stakeholder perceptions that PBR had not been designed to benefit all parties. The lack of a benefit sharing mechanism likely also exacerbated the concerns with respect to Enbridge's outsourcing contracts. PBR gains more political support and has been more popular with stakeholders when they share in the cost savings resulting from performance improvements, such as outsourcing.

The second factor is the term of the plan. Both LDC PBR plans in Ontario had three-year terms. This may, in part, reflect the plans' experimental nature. However, incentives are naturally strengthened as the PBR plan's term, and the period between COS rate reviews, increases. Five-year plans are more standard in PBR, and plans as long as 10 years have recently been implemented in Massachusetts. Extending PBR plan terms in Ontario may help amplify the benefits from PBR and thereby enhance benefits to all parties, especially if tied to an earnings sharing mechanism.

The third factor is whether PBR is targeted or comprehensive. Most PBR plans are comprehensive in nature and create stronger and more balanced incentives. For example, a plan that focuses only on O&M operations may weaken incentives to control capital costs, with the effect that overall performance incentives may not be improved. Differential regulation of O&M and capital costs can also, unintentionally, create incentives for firms to allocate costs differently. These issues have been prominent in the most current update of price controls for U.K. power distributors. That said, the extent of

LDC regulation will vary if Ontario decides to unbundle more utility services to competitive market regulation. We address this matter below.

The targeted nature of the Enbridge PBR plan may have played a role in the dissatisfaction this plan generated. In particular, the outsourcing undertaken by Enbridge may have been less controversial if the PBR had applied to all operations instead of just O&M. In a comprehensive PBR application, there would have been fewer concerns that Enbridge was attempting to cut its O&M expenses at the same time it was capitalizing more costs and thereby adding to rate base and future earnings. A comprehensive PBR plan would create more balanced incentives with respect to cutting both capital and O&M costs.

The fourth factor undermining some parties' perception of PBR is the need for technical expert opinion and input on specific PBR parameters. Some stakeholders think that the need for outside expert advice invites "dueling consultants" and technical debates that OEB staff and members are not well positioned to understand. The desire to avoid both the costs and, more importantly, the risks of arbitrary decisions on these parameters has contributed to the LDCs' desire to implement a more simplified PBR approach.

All else equal, simplicity in PBR design is a virtue, but regulators must still ensure that rate adjustment mechanisms are just and reasonable. Indexing formulas that utilize industry productivity and input price evidence are supported by a well-developed conceptual framework and ample regulatory precedents that affirm the approach is "just and reasonable." It is less clear how "simpler" formulas should be analyzed to determine whether they yield just and reasonable rate adjustments. In addition, there has been much consensus on productivity and consumer benefit sharing measures in regulatory proceedings. This experience implies that, in practice, the risk of arbitrary regulatory decisions resulting from difficult technical evidence is overstated. The fifth factor is choosing an appropriate inflation measure. The Union Gas PBR formula included a 1.1% inflation differential, which is a high outlier among North American plans. Increasing the value of X caused some parties to doubt whether PBR was fair. Coupled with no retail customer benefit sharing, this combination seemed too extreme. A lower X-factor and some sharing could be both more popular and achieve better performance results. The issue of inflation differentials might best be resolved by constructing an industry-specific inflation measure for gas distribution services. This approach was employed in the electricity power distribution proceeding and preferred by the OEB in the Union case. Issues surrounding the desirability and details of constructing industry-specific inflation measures should be addressed.

SECTION 4. Summary of *Status Quo* Regulatory Issues to be Addressed

There are several specific important regulatory issues in Ontario that the NGF addresses. These are:

- *COS regulation vs. PBR*: The first threshold issue is whether traditional COS regulation or some form of PBR should be implemented to regulate natural gas utilities in the Province. COS regulation is less risky but also creates weaker performance incentives to reduce costs, including regulatory costs. In contrast, PBR can be designed to create stronger performance incentives, which can create efficiencies that benefit all stakeholders. There is greater utility business risk with PBR, which needs to be matched with the opportunity to earn a higher return. Some aver that because PBR is less familiar, there are also greater regulatory risks. For example, regulators could choose the "wrong" value for a particular PBR parameter or change the rules mid-stream.
- *Comprehensive vs. Targeted PBR*: If PBR is preferred to COS regulation, should PBR apply to all costs associated with the LDCs' various delivery services or only a subset of costs? The narrow approach has been tried for Enbridge. The more extensive approach has been used for both Union Gas and the Province's electric power distributors. A more comprehensive PBR is more likely to reduce regulatory costs. It is also much more common. However, comprehensive PBR may involve greater regulatory costs to implement and may also involve greater risks for both utilities and customers, depending on the choices for PBR parameters and the specific design selected.
- If comprehensive PBR is preferred, the OEB must also reach decisions on the relative merits of:
    - Price cap or revenue cap applications.
    - Price freezes or indexed price changes.
    - The use of productivity and input price measures in any price adjustment mechanism during the PBR term.

- Earnings or benefit sharing mechanisms or end-of-term regulated price adjustments.

Price caps generally create the same incentives to control costs as do revenue caps. However, price caps create much stronger incentives to pursue allocative efficiency by encouraging companies to pursue cost effective load and customer growth. Some stakeholders may not view this aspect of price caps as an advantage because it can conflict with promoting conservation. The OEB's business plan seeks to create a "culture of conservation." Other things equal, revenue caps are preferable to price caps for achieving conservation. However, conservation efforts can also be encouraged with targeted demand-side management programs and specific PBR incentive measures. These can also be coupled with price caps. It may therefore be important for stakeholders and other interested parties to examine whether they prefer revenue caps or instead price caps plus targeted DSM incentives given the OEB's conservation goals.

If there is a preference for "simple" rate adjustment mechanisms during the PBR term, the OEB will likely seek some assurance that resulting pricing changes would satisfy the just and reasonable standard. This would appear to require some standard for evaluating the reasonableness of rates not just for a single period, but for multiple periods within the plan's term in the future. If simple rate adjustment mechanisms are not deemed to be appropriate or feasible, the PBR's term should be shorter in length. That said, using interim price adjustments based on already tested adjustment mechanisms would provide a strong utility incentive. Both regulators and stakeholders need to be involved in this process at the outset. Union Gas' previous experience points to the inherent difficulty in such efforts. The following matters need to be addressed:

- *Benefit sharing*: Appropriate benefit sharing arrangements are a key stakeholder concern. Further stakeholder input is desirable on the following issues:
    - Should a PBR plan have an earnings sharing mechanism (ESM)?
    - If so, should the ESM allow earnings that are both above and below the allowed ROE to be shared with customers?
    - Should the sharing fractions above and below allowed ROE be symmetric?
    - Should the ESM have multiple sharing fractions for different levels of realized earnings? If so, should these multiple sharing bands be progressive (the utility

keeps incrementally greater shares of earnings as earnings increase) or regressive (the utility keeps incrementally smaller shares of earnings as earnings increase)?

- Should the ESM have deadbands? If so, what is the proper magnitude(s) of these bands?
- In an index-based mechanism, should there be a productivity stretch factor, or consumer dividend? If so, what is the proper basis for determining such a factor? Should the magnitude of the stretch factor depend on the cost performance of the company with, for example, larger stretch factors for firms that are less cost efficient?

These questions are most important. Retail customers must support PBR if it is to be successful. This means that customers need to share in any cost savings or efficiency gain benefits. Two approaches are available. First, when retail prices are reset at the end of the PBR term, any cost savings would typically inure to retail ratepayers in lower going forward prices. Second, ESMs provide a formula for sharing utility gains achieved during the PBR's term between customers and owners.

The regulatory challenge is to provide strong and extended period incentives to promote efficiency, while at the same time drawing retail customers into the PBR process by sharing with them the benefits achieved.

ESMs combine both risk mitigation and benefit-sharing devices. An ESM will mitigate the risk of earnings shortfalls for companies if it allows "downside" earnings to be shared; it will naturally mitigate the risk of unacceptably high earnings as more upside earnings are shared (*i.e.* if the ESM is regressive). However, there is at least some tradeoff between risks, rewards, and incentives. Extensive contemporaneous customer claims on the potential benefits from cost reduction initiatives or regressive ESMs will limit utility performance incentives. Similarly, larger deadbands around allowed ROE and/or progressive sharing mechanism where the greater the savings, the greater the utility benefits, would increase utility performance incentives but increase utility risk.

This report contains information on retail consumer benefit sharing in approved indexing plans. These PBR approaches have generally been similar. However, some utilities aver that they should be subject to smaller consumer sharing plans if they are already relatively cost efficient at the outset of the plan. There is an intuitive appeal to this argument, since companies that are relatively cost efficient will have less "fat" to cut and thereby fewer opportunities to expand productivity growth. Requiring utilities and other parties to present evidence on their relative cost efficiency raises regulatory costs and the technical complexity associated with the PBR design and implementation proceedings, and may invite further controversies. This issue supports simpler approaches with greater customer sharing that occurs sooner rather than later.

- *Plan updates*: PBR's incentive effects depend on what happens when the PBR plan is updated at the end of the PBR's term. Among the issues that would need to be addressed are:
    - What information should the OEB consider when updating a PBR plan?
    - Should there be a new COS rate case to reflect new costs and sales? If so, should there be a full COS or true up at the beginning of the next plan?
    - Some plans (such as those for National Grid-MA) have featured partial COS true-ups according to formulas established in advance. The pros and cons of "partial" COS need to be considered. This would also involve the magnitude of any COS true-up based on the firm's performance under the PBR plan.

The OEB has, to date, been reluctant to specify how it will evaluate PBR plans when they expire. More "hard-wiring" of plan termination and subsequent updates will almost certainly be sought and could enhance performance incentives. This will also reduce regulatory flexibility and the reduce regulators' ability to respond to unforeseen future developments. .

- *Regulatory menus*: A "menu" or handbook of regulatory options was initially made available for Ontario's electricity distributors. A similar PBR menu approach for LDCs could perhaps be useful and appeal to the different PBR preferences of the regulated natural gas LDCs. The salient issues are:
    - What are the pros and cons of a menu approach?
    - What combinations of regulatory parameters can be considered? Options include different X factors and ESMs, a menu of different X factors and PBR plan terms, and different X factors and plan update provisions.
    - How should the menu of options be developed?

- What regulatory process should the OEB use?

In evaluating these issues, stakeholders should bear in mind that, by their very nature, a menu approach is designed to enhance regulatory and utility flexibility. This has the obvious appeal in that it prescribes more than just a "one size fits all" regulatory model. Some stakeholders may, however, value consistency across regulated entities, in part to encourage benchmarking and LDC performance comparisons. There are many regulatory challenges in designing a comprehensive and appropriate menu.

- *Regulatory monitoring and costs*: Some stakeholders have expressed dissatisfaction with the level of regulatory monitoring and associated regulatory costs in Ontario. Among the issues to be decided are:
  - Should reducing regulatory costs be an important regulatory objective?
  - If so, how can such costs be reduced? Are there any current reporting requirements that can be simplified or eliminated?
  - Does PBR increase costs in the short term, but reduce them in the future? Or, does PBR increase regulatory costs, which are the "price" paid for greater efficiency and lower utility prices?

One of the objectives of the OEB's business plan is streamlining the regulatory process. Some stakeholders conclude that not all stakeholders are committed to this goal. Any such regulatory streamlining should not be achieved by sacrificing the transparency or consultative nature of the regulatory process.

- *Rate rebalancing*: The OEB has rejected rate rebalancing in the PBR plans for both Union Gas and the electricity distributors. This rejection was based, at least in part, on an expressed lack of understanding on how such pricing flexibility and true-up accounting could work under a cost indexing PBR plan. Pricing flexibility provisions can have important incentives under PBR. Among the issues to be decided are:
  - What are the pros and cons of allowing greater flexibility in the pricing of distribution services?
  - Should pricing flexibility permit
    - Different rate adjustments for different services or customer categories, subject to the overall price cap index or revenue

constraints, as well as any conditions established on allowed price changes for any service or rate element?

- If so, what actual price index formulas are the most appropriate way to implement pricing and balancing flexibility? What should be the bounds of allowed price change (*i.e.*, magnitudes of side conditions) for individual services?

- *Service quality*: The OEB has an important role in regulating gas distribution service quality. Supplying a reliable high quality product is a given for regulated utilities. These are:
  - Should service quality be regulated using the existing monitoring framework or through financial incentives?
  - If the latter, should the service quality incentive allow for penalties and rewards or be penalty-only?
  - Should penalties and rewards (if allowed) be implemented via rate surcharges and surcredits or via changes in the allowed ROE, which then affects the operation of the ESM?
  - Should the magnitudes of penalties and rewards for individual service attributes be based on estimates of their value to customers, the cost to companies of improving service, or something else? Some parties have recommended that research on customer willingness to pay for changes in service quality be undertaken in conjunction with considering these issues.

Additional details on service quality regulation can be found in Appendices Four and Five. Regulators throughout North America are increasingly relying on formal incentive mechanisms to improve service quality and less on informal information reporting and monitoring approaches in service quality regulation. There are some start-up costs in designing formal SQI plans, but there are also many regulatory precedents that can be drawn on. The value of penalties and/or rewards applied to individual performance measures are also critical for the incentives established by the plan.

The various PBR issues raise specific questions. The most important are:

- The optimal term for the PBR plan (*e.g.,* 3 or 5 years?).

- How should the OEB establish customer benefit and sharing mechanisms to gain customer support for PBR?
- Whether total factor productivity (TFP) studies should be used in the PBR plans, and if so, would they be based on company-specific or industry TFP trends? If the latter, would the definition of the industry would be nationwide, regional, or Provincial?
- Available data sources and TFP studies.
- Whether the inflation adjustment measure should reflect economy-wide or industry-specific inflation measures; if the latter, the available data for constructing industry-specific inflation measures.
- Is it beneficial to determine a specific menu of regulatory options? If so, how should the OEB achieve this goal?
- Specifying particular “offramps” in the case of undesirable PBR outcomes.
- Specific magnitudes for penalties and rewards of different service quality attributes in service quality incentive plans.

SECTION 5: Regulatory Implications of Changes in the Status Quo

Prior sections focused on regulatory choices for comprehensively regulating the natural gas LDCs in Ontario. Regulation in any form, be it COS, PBR, or something else, needs to be matched to the policy choices confronting Ontario. The regulatory system is an important component of a broader set of policy questions, and *vice versa.*

The degree of competition also matters. Regulation and competition must be reconciled generally, and placed in context before the OEB. Regulation may change, but will not be eliminated in the utility industry. There are several reasons why regulation will continue beyond the price regulation of natural gas networks. First, the various natural gas network and ancillary services must remain viable and secure. Second, consumer protection and supply security are essential regulatory functions. Third, core consumers may not have enough use or economic interest to bother with the details and volatility of complex natural gas markets. LDCs, or some other entity, most likely will be subject to regulation as SOLRs and core market providers for small volume customers. Fourth, competitive entry and affiliate codes of conduct require rules, regulations, dispute resolution, and enforcement. Fifth, rules against intentional market manipulation plus monitoring markets to detect unanticipated adverse outcomes will increasingly become necessary. Sixth, new supplies and delivery options must be financed and brought on line in the future. Ontario needs to look no further than California's power crisis to learn this latter lesson and that regulating competitive utility markets is neither an oxymoron nor redundant.

Some facts are important. The LDCs in Ontario currently retain a portion (slightly more than a third of the volume) of the natural gas system supply functions and responsibilities. This entails mixing detailed system supply regulation for some natural gas customers, along with others that are free to secure supplies in competitive natural gas markets. The former requires price regulation (*e.g.*, COS or PBR). The latter must insure workable competition and that ease of entry exists. For example, establishing competitive markets often requires an initial regulatory inquiry to determine if there is market power. This could mean expert studies to measure market concentration, Herfindahl-Hirschmann Index (HHI) analyses, market entry possibilities, and determining demand and supply elasticities. An additional regulatory requirement for competitive markets is to expand market monitoring.

Ultimately, the focus will be on matching policy choices and regulatory requirements. At the initial state, the focus needs to be on thoroughly airing basic interdependencies.

Regulated energy utilities are often assigned an SOLR responsibility. Regulators can then be reasonably certain that if competitive retail providers fail to provide their services or exit the market, retail consumers, particularly residential and small commercial customers, would be assured service. This SOLR role is jointly applicable to both the consumer service functions and natural gas system supply. If the LDCs exit this role, some other entity must be assigned this responsibility. Retaining SOLR in Ontario means that regulators can encourage entrants for new energy services without imposing heavy handed regulation on these new competitive retailers.

These system gas and customer protection or reinstatement service functions are all important. However, they do not reflect the only important distribution function. The other crucial functions are system reliability and load balancing. Natural gas is put on the network and taken off at numerous points. Volumes, pressure, and congestion are physical factors that require a single network manager or operator to secure and supply these network or ancillary services.

If these network reliability and externality factors are ignored, the distribution system would crash and become unreliable. Some consumers would contract for but not receive natural gas. Others would not contract or pay for natural gas but would be able to consume the natural gas.

Balancing system load, protecting pressures, and avoiding congestion are all network functions. Distribution companies provide these functions in their system reliability role. The LDCs internalize such network externalities using a regulated cost of service for the system. The crucial point is that some entity must perform this network operation function. Markets and customer choices are possible here. However, a single network operator is still required. A complementary principle is that the costs of internalizing network operations such as load balancing need to be allocated to retail consumers in some fashion. The mix of COS and competitive markets in Ontario to secure these services would not affect all customers to the same extent. Today, LDCs have this exclusive role and they currently use mostly bundled COS approaches for supplying network services.

Most natural gas regulators have opted for a continuing regulated distribution role for internalizing these network reliability matters. If distributors retain a system gas function, this continued network reliability function is somewhat easier to achieve. If system gas is no longer a distribution company's responsibility, the distributor would still need to access natural gas supplies to balance load. This often can increase the costs because real time spot commodity purchases are typically more expensive than long-term, LDC system supply portfolios.

On some level, and for some core customers, utilities will likely always be perceived as continuing to provide these network functions. Accordingly, regulators and governments are wise to embrace this fundamental public perception and political fact. Resource adequacy and sufficient investment in infrastructure and public safety require a strong and continuous regulatory and governmental role. The LDCs most likely are the best choice to secure network reliability and to expand infrastructure.

It is, however, possible to unbundle some of these network services and to introduce new customer choices. Those would include: (1) options for customers to eschew utility provided ancillary services and to either purchase or own assets to self provide them; (2) opportunities for consumers to turn back or sell reliability and other services that they are flexible enough not to require; and (3) encouraging entry of new competitive suppliers to reduce the costs of these services.

One of the core themes of the NGF is that the specific provincial policy choices and regulation are interdependent. Paradoxically, either retaining the *status quo* LDC roles or altering the policy for the LDCs affects the approach and opportunity for expanding the use of PBR in Ontario. At one extreme, more extensive policy changes would, to a much greater extent, rely on market forces to regulate. Accordingly, such policies would actually reduce the degree of current COS or PBR regulation of LDCs in Ontario. As explained above, competitive market regulation, both in the formative state and ongoing monitoring, would likely expand in Ontario, if the focus moves away from LDC provided services.

The paper puts these matters in context by considering three potential regulatory end states for three types of LDC service categories that have taken center stage during the stakeholder interviews: (1) System Gas, (2) Ancillary Services and (3) Storage. The NGF considers three different policy packages for each of these LDC services: (1) *Status Quo* policies; (2) Incremental Policy Changes; and (3) Extensive Policy Changes. System Gas and Storage are also the subject of two additional, more comprehensive papers filed concurrently in the NGF with this regulatory overview paper. Here, we briefly describe these three services before outlining the three policy packages. For a more detailed view, please consult the other discussion papers.

A. System Gas

LDCs currently supply system gas as a bundled product. This system natural gas is supplied and delivered to retail customers under a quarterly price adjustment process (QRAM). The LDCs do not earn a margin or net income on the retail sale of natural gas.

There are two major and two minor competitive natural gas retailers in Ontario that also sell natural gas to small commercial and residential customers. The LDCs have more customers, but sell less gas than the combination of competitive marketers for both small volume and industrial users, as well as direct retail purchases.

The residential competitive retailers sell a fixed price product, which the LDCs are not permitted to provide. In addition, larger volume natural gas users, fairly universally, purchase all their natural gas either directly or through natural gas marketers. The two larger LDCs in Ontario currently sell about 35% of the natural gas consumed. Something close to this percentage amount may be required if the LDCs retain the other network services in Ontario in order to provide load balancing and network reliability.

B. Network or Ancillary Services

Natural gas distribution companies in Ontario currently provide important network services such as load balancing, maintaining natural gas line back pressures, back-up system supplies, peak shaving, storage, etc. When these regulated companies were fully integrated, these services were typically bundled together with gas acquisition, delivery and customer services costs. Even though gas supply or commodity costs have been unbundled, other retailers sell, and direct customers purchase natural gas in Ontario, the LDCs continue to provide these ancillary services or network related benefits at COS prices to all markets and end users.

These network services are reasonably well known and could be operationally unbundled. If the LDC does not operate the distribution network, some other independent network operator (INO) would need to perform these roles. Under such policies, some of these services could be purchased and/or traded in a competitive manner. Alternatively, the LDC could continue to internalize network externalities using market based choices as discussed previously. This would unbundle ancillary services, expand the use of and increase price transparency for these network services.

C. Storage

The LDCs in Ontario either own or contract for storage for their bundled system gas customers, as well as for most of the directly served and marketer supplied customers. This LDC storage helps the LDCs to internalize network externalities. The LDCs also sell or lease storage to others and each other at market based prices. The current system is generally perceived to be a regulated monopoly function with a medium degree of flexibility and transactional innovation. COS pricing is used for in-franchise or native load system gas and distribution customers.

Some would like to open the storage service. Others are content to have the LDCs do the work, including securing transportation to and from storage and to restrict the LDC's price charged to system gas competitors to COS service levels for these storage services.

There are also two new concerns. First, power generation can swing swiftly, causing additional storage/load balancing and line pack concerns. Some stakeholders favor allocating incremental cost to power generators. Second, there is a need for new storage development and greater opportunities for competitive storage in Ontario.

Union Gas currently has more storage than its native customer load requires. Union Gas sells its excess to Enbridge and others at market based rates, which are determined by competitive bidding. These various storage matters introduce several regulatory concerns such as market power, affiliate interest, transportation access, ownership, and market monitoring. The paper is focused on these aspects of regulatory and policy changes in Ontario. There is also a separate discussion paper on storage.

D. Policy Packages

For each of these three core LDC service categories, we consider three separate packages, or options, for the future. These are maintaining the *status quo*, implementing incremental policy changes, and implementing extensive policy changes. We now discuss each service category in the context of each of the three packages.

1. Package 1: Maintaining the Status Quo

This package retains the *status quo* and limits potential changes to some specific stakeholder suggestions.

a. System Gas

Retail consumers currently have retail supply choices. All natural gas customers in Ontario, regardless of their system gas supplier, benefit from the LDC's system gas role in terms of SOLR and Gas Distribution Access Rule (GDAR) protection, load balancing, back-up service, and having a strong credit-worthy guarantor of new system expansions and future natural gas supplies.

The *Status Quo* achieves consumer protection using a mix of competition and regulation in Ontario. Additional smaller policy changes are still possible. Currently, only the LDCs' retail competitors can sell fixed price contracts. This may help insure entry and competitive choices for the core customers or the small volume market.

If LDCs are permitted to sell fixed price natural gas contracts for specific terms, the OEB would need to determine how to regulate such sales. One approach is to use a form of PBR in which the LDCs, like the competitive marketers, are fully at risk. Another approach would use deferral accounts and ESMs that would enable customers taking this option and LDCs to share potential risks and rewards.

The NGF will assess the appetite for such changes and the possible competitive concerns that marketers might raise. Alternatively, the current approach could continue using a QRAM make whole approach.

b. Network or Ancillary Services

The current system for internalizing network externalities works quite well in Ontario. This could continue with little consequence.

These are two potential concerns: (1) whether the current cost assignments for these services are fair and efficient; and (2) whether there are any anti-competitive effects if the LDCs retain this function. In addition, PBR could be used to adjust earnings and sharing if the LDC under or outperforms when providing ancillary services.

c. Storage

The LDCs have invested in and developed existing storage under COS regulation. Maintaining the *status quo* recognizes this prior prudent investment. Changing to a more competitive regime by forcing the LDCs to divest their storage assets could result in subsidies for some customers to the detriment of others. Furthermore, while future developments could cause current policies to be reexamined, there has been little demonstration that the current arrangement needs to be fixed. The LDCs supply storage to their direct retail sales customers and direct retail distribution customers at cost. There are two key questions with respect to maintaining or reflecting the *status quo.* First, should the LDCs offer other LDCs cost based or market based storage? Second, should the market set the price for all storage sold, with the LDC's owners and in-franchise or native load retail customers sharing the benefits?

2. Package 2: Incremental Policy Changes

This package increases market based approaches in Ontario.

1. System Gas

Under this approach, the choices that the LDCs provide (*e.g.*, permit them to sell one year, fixed price, small volume natural gas contracts) would be expanded. At the same time, regulators would need to test market power and to consider how to expand the entry of new ESPs and how to increase the small volume retail customers' understanding of choice. If LDCs take on volume risk and offer different price options, regulators could either use PBR for performance, price, and quantity issues, or let the LDCs' earnings be at risk. Earnings sharing may also come into play.

One possibility is initially to assign all customers to ESPs and to require the customers to make an affirmative decision to return to or to stay with the LDC. The current small volume retail marketers have not established either a portfolio or permanent presence in the Ontario market. Without deeper roots, it may not be possible to assign the LDCs' system gas customers to third parties or current energy service providers.

The OEB would likely need to establish entry and other operating requirements for energy service entities, as well as determine it will protect small volume retail customers. In addition, the OEB may find it important to require a certain proportion of system gas to remain with the LDCs in order to insure that the LDCs would continue to supply other important network reliability functions.

2. Network or Ancillary Services

Ontario could also seek a middle ground between the current regulated approach and a full market-based approach for network services. Here, caution is recommended because these network or ancillary services are truly utility services best suited to COS/PBR regulation. Certain ancillary services, such as load balancing, line pack pressure and storage could be moved to either a market based pricing paradigm or at least to an unbundled regulatory tariff. This would affect what different customers pay, rather than cause the LDCs to abandon this function. One change is simple. This would be to permit customers that are willing to do so, to self supply these ancillary services and to reduce the prices paid to the LDCs. This would also likely provide benefits to other network customers when the LDCs respond operationally. This approach is complex, but less so than other, more extensive policy changes we discuss below.

3. Storage

An incremental policy change would begin with permitting or encouraging new non-LDCs to enter the storage market in Ontario or Michigan with transportation rights. Such an approach would likely also set terms and conditions to allow third parties or direct purchase customers to acquire some of the existing LDC storage and to bring into the market new storage inside and outside the province.

Regulators would need to set the terms and tolls for storage access, transportation, and facility operations. Alternatively, the OEB could specify how it would measure market power and control potential abuses. A two-tier hybrid pricing approach (COS and Market Based) could be devised. Under the COS approach, there would be less need for PBR regulation, under a Market based approach, the OEB would need to establish how risks and rewards would occur and markets monitored to insure workable competition. These PBR approaches would be difficult to arrange.

As with any mid-level concept the regulator would need to establish a just and reasonable solution. Doubtless, this approach would change and evolve over time.

3. Package 3: Extensive Policy Changes

1. System Gas

This option would represent the opposite extreme to maintaining the *status quo*, such as forcing the LDCs to exit the system gas business. If LDCs were no longer providing system gas, the policy focus becomes how to regulate competitive retailers. Regulators would need to address GDAR and other duty to serve matters. The LDC's roles in SOLR, balancing load, back-up service, storage, and guaranteeing new supply additions would either need to be replaced by new entrants or turned over fully to market forces.

Thus, regulators would need to determine and designate a SOLR and GDAR. Further, upstream allocation of FTR and storage would need to be accomplished. This package would require assigning all retail load to a competitive retailer. Choices would expand, and each retailer could offer an unrestricted menu of choices, much as is currently available for large industrial users.

Given the essential services nature of natural gas and consumer protection, there would need to be strong regulatory oversight or even some type of retail ESP regulation. At the very least, a new entity that replaces the LDCs would need to be formed to guarantee core market access to natural gas supplies. Such an expanded regulatory outcome could conflict with the more purely competitive notion of a full market based solution.

2. Network or Ancillary Services

Some political jurisdictions have determined that unbundling ancillary services does two things. First, there are better and more transparent price signals. This is fair and efficient. Second, market participants have a new choice. They can bid to alter their use and/or to provide others such ancillary services. The latter is likely more efficient. Some customers will likely pay more if they ignore these changes and continue to conduct business as usual.

The primary regulatory question is whether or not the increased complexity would cause high transaction and information costs. If this is likely, the benefits of the change may not be sufficient to justify the costs of this option.

Generally, we conclude that it is best not to have extensive policy changes in the network or ancillary services area because, as we noted above, these services are truly monopoly or single entity functions and best regulated by COS regulation with modest PBR additions. If LDCs exit this role, there is no upside for the utilities in running an efficient ancillary services market. An independent network operator would also become necessary.

3. Storage

Another major change in Ontario is that some stakeholders suggest having the LDCs divest some or all existing storage. Full divestiture would seem to go hand in glove with a full LDC exit from the system gas business because if the LDC no longer had a system gas responsibility, their need for storage would be vastly reduced. Conversely, if the LDCs retained system gas responsibility, they would need to retain some role in storage in order to perform their responsibilities. This would mean that there would be no COS or PBR regulation for storage. An alternative would be to tag a portion of existing storage to groups of retail consumers, much like upstream transportation rights, if the LDCs exit the retail system supply business.

The OEB would also need to consider how the LDCs would divest storage assets. Two possibilities are likely to be proposed: (1) sales or transfers to affiliates; and (2) a competitive market auction. Regardless, the OEB would also need to determine what to do, if anything, with any market to book premiums for the transfer or divestiture of storage assets.

Customers who either purchase or contract for storage could also be permitted to sell or lease the storage in a secondary market. All these variants on a market-based storage pricing model would need to resolve issues related to who would operate storage, manage peak use and other reliability matters, and arrange or coordinate transportation or delivery “in” and “out” of storage.

If system gas responsibility is retained by or returned to the LDC, then PBR could be used to regulate the storage services that LDCs own or purchase on behalf of their customers. However, if the LDCs exit system gas and storage, COS regulation and PBR would focus on delivery and other customer services. Markets, not regulation, would establish storage prices and access.

Section 6: Conclusion and Evaluation Criteria

The NGF addresses a myriad of interrelated policy matters and regulatory models. Nothing has been predetermined. The three policy packages are offered to bring focus to real choices for Ontario and because the stakeholder interview process raised such options.

The final policy choices rest with the OEB and/or legislation. We turn to some of the factors that seem important to the review and evaluation of the choices for Ontario.

As we discussed in Section 2, an important framing issue is the evaluation criteria to be used to review the various policy and regulatory packages. Natural gas is an essential commodity for Ontario's economy and consumers. With this fact clearly in mind, we previously identified efficiency and fairness as the cornerstones of the criteria needed to evaluate policy packages. The following discussion restates the key elements of these key criteria, which will be used to evaluate the various options available under each package.

A. Efficiency

1. Economic Efficiency.

This criterion has two important facets. First, benefits must exceed costs and net benefits are optimal Second, the quantity of natural gas consumed is optimal. Optimal consumption means that more consumption would reduce net benefits because marginal costs exceed willingness to pay or marginal benefits. At the same time, less consumption would also reduce net benefits because willingness to pay or marginal benefits exceed marginal costs and Ontario would improve economic efficiency or net benefits by expanding natural gas consumption.

3. *Dynamic Efficiency, (or infrastructure investments).*

Regulators and governments ask different types of questions related to investments under COS and market based regimes. The objective of these inquiries is generally the same; to wit: will sufficient new infrastructure investments occur?

Under regulation, this can take forms like integrated resource planning, rate base/prudence reviews, etc. Also, comprehensive PBR can substitute for a regulatory command and control paradigm. Under competition, there are issues such as congestion pricing, capacity rights, and secondary markets. Regardless, no regulatory or market based system exists in any "pipes and wires" industry that totally satisfies the dynamic efficiency or infrastructure investment requirements even though one can still consider the investment incentives under different types of regulation and choose the option that creates better incentives.

Some systems work better than others. Much attention is paid to this matter. As a criterion, it needs to be included. This is not because it is a decisive matter. Instead, it is simply too important to overlook, even if we do not fully know what to do about it.

B. Fairness

1. Consumer Protection.

Governments and regulators properly seek to protect consumers from anti-competitive activities, undue price discrimination, and market manipulation or unjustified market gaming. In addition, some consumers have a relatively small stake in natural gas markets. They have more pressing economic, social, and personal interests. Such relatively small volume or core consumers generally rely on government regulations to be protected.

2. Income Distribution.

Economists draw a sharp conceptual distinction between economic efficiency and so-called transfer payments. The first concept discussed above, efficiency, means that society is made better off and net social benefits are increased. The second concept discussed above, transfer payments, focuses on who pay and how much. For example, a single supplier that could charge a consumer the exact price at which the particular consumer valued the natural gas would perfectly discriminate by charging each consumer a different price for the same commodity. Such a seller is called a perfectly discriminating monopolist. Such a seller would only sell more natural gas if consumers were willing to pay prices that equal or exceeded the marginal costs of natural gas supply. The last consumer served would pay precisely a price that equaled marginal cost. This would represent a level of consumption/supply that was economically efficient. There would be net benefits lost if more or less natural gas was sold.

The problem is that the perfectly discriminating monopolist would collect all economic surplus that exists between total benefits or willingness to pay and the total cost of the natural gas supply.

Competitive markets split, albeit not necessarily on an equal basis, (1) the consumers' surplus differences between the different willingnesses to pay and single market clearing price all consumers pay for a competitively supplied product; and (2) producers' profits for the difference between the single market clearing price and the total costs of production.

As long as consumption or output is unaffected, economic efficiency does not become concerned with who pays what. Individual losses or gains, such as the discriminating monopolist that takes all the surpluses, affect income and wealth transfers, but not necessarily economic efficiency.

Economics can be focused too closely on the optimal natural gas volumes. Another criterion for regulators and stakeholders is the extent of any unjustified or undue transfer payments and discrimination. Many parties have interests at stake, and regulators have to consider the fairness (*i.e.,* benefit distribution) associated with their policies. There are also regulatory process fairness issues (*i.e.*, outcomes are seen as more fair as the process becomes open and consultative and as the basis for regulatory decisions is transparent and verifiable). However, there is often a tradeoff in attempting to achieve regulatory process fairness and the regulatory costs that result; judgment is necessarily involved in attempting to optimize this tradeoff.

3. Transparency and Choice.

Choice is also a means towards the end of efficiency – usually a more effective means in non-natural monopoly services where competition is feasible. These matters relate to whether consumers understand fully what it is that they are receiving and how much these components cost them.. Terms such as unbundling, better price signals, and cost causality are all important. The goal is to ensure that consumers understand that they are not limited to choosing only a single scoop of vanilla ice cream. Rather, they have a choice of many flavors, portion size and toppings, all available for a certain price. The key is knowledge. The more consumers know, the more options they will have and the greater the opportunity to make better and more satisfying choices.

Not long ago, telephone service was a take-it-or-leave-it, plain vanilla telephone service. Today, the cellular phone, voice mail, pre-paid phone cards, the internet, fax machines, competing suppliers for phones, local, and long-distance are all available in a dizzying array of sizes, prices, and styles. We no longer have to worry about paying just and reasonable prices for plain old vanilla phone service.

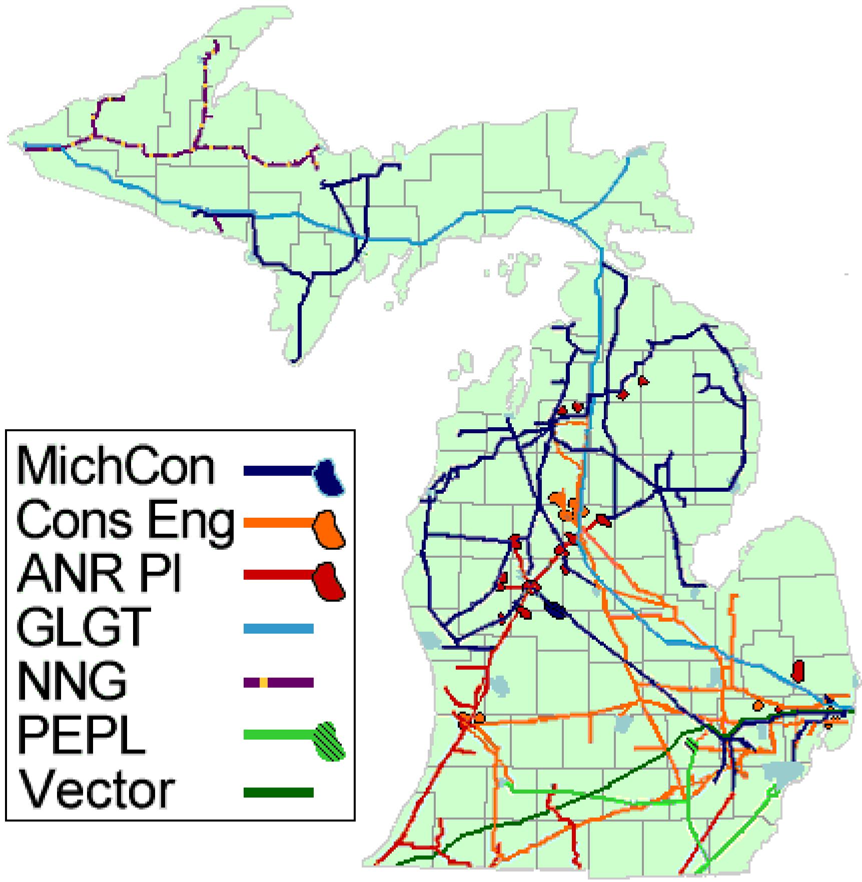
Instead, regulation and competition present telephone consumers with many "choices". This phenomenon has begun to spread to other pipes and wires businesses. This has become so commonplace that how successful or not different industry and regulatory structures are in providing transparency and choices is now a full-fledged evaluation criteria.

These various evaluation criteria can and should be used in the NGF process to compare the three policy packages we discussed above from both an *ad hoc* and integrated perspective. This review would need to be combined with the overarching regulatory model that would best support success for Ontario.

When market based solutions are chosen, traditional regulation needs to be relaxed. Regulatory oversight over market monitoring, terms of service, and codes of conduct need to be expanded. If, as in Package 1, LDCs retain network, system gas, and storage roles, regulation needs to continue in either its current COS form or more likely with an increased role for PBR.

To the extent that LDCs continue to operate as regulated monopolies, PBR has a greater role to play to insure economic efficiency gains. To the extent incremental policy changes, such as Package 2, are implemented, a mix of COS and market regulation would be required and PBR's role would likely be more modest. More extensive policy changes most likely re-direct regulation rather than cause regulation to be eliminated. That said, workable competition, not regulation, would take on a greater role under Package 3.

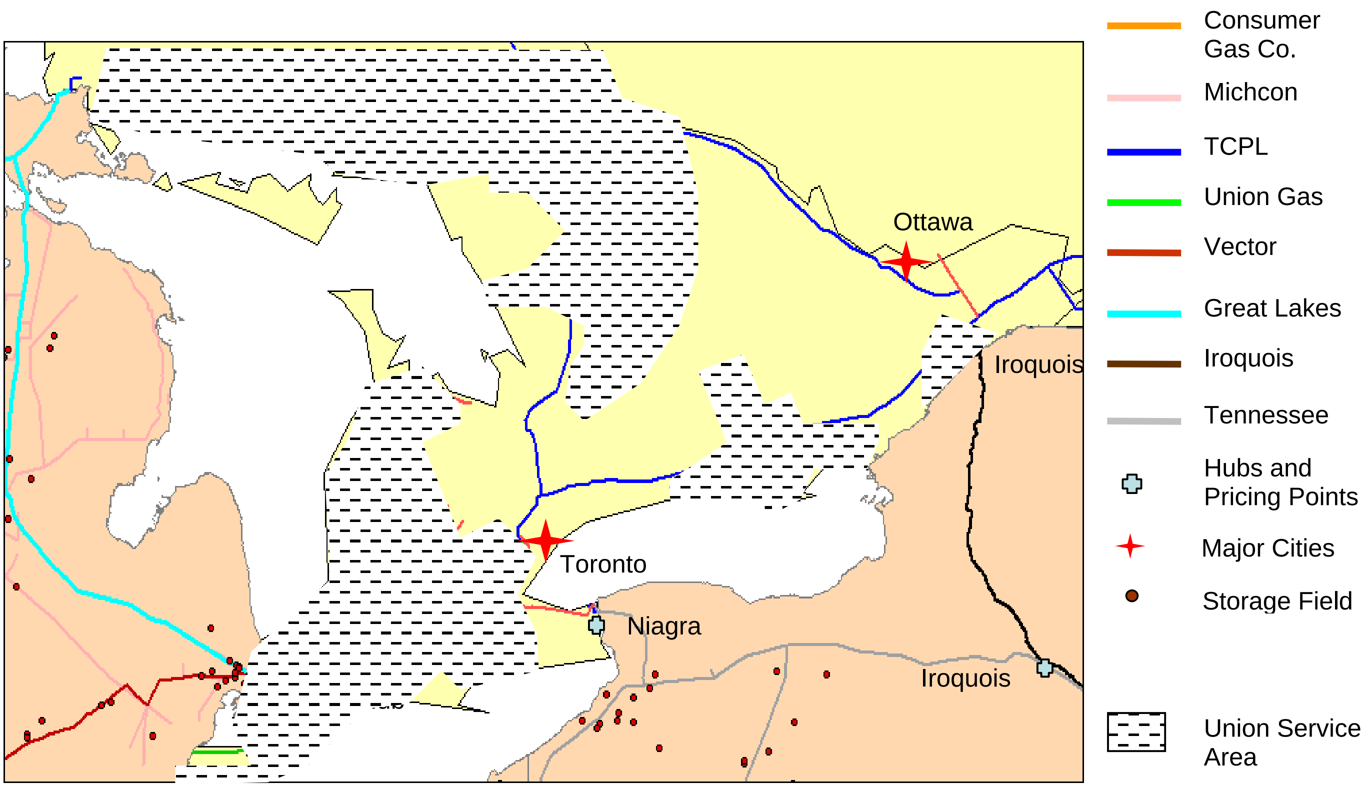
Appendix 1
Map 1
Michigan Storage



Appendix 2

Map 2

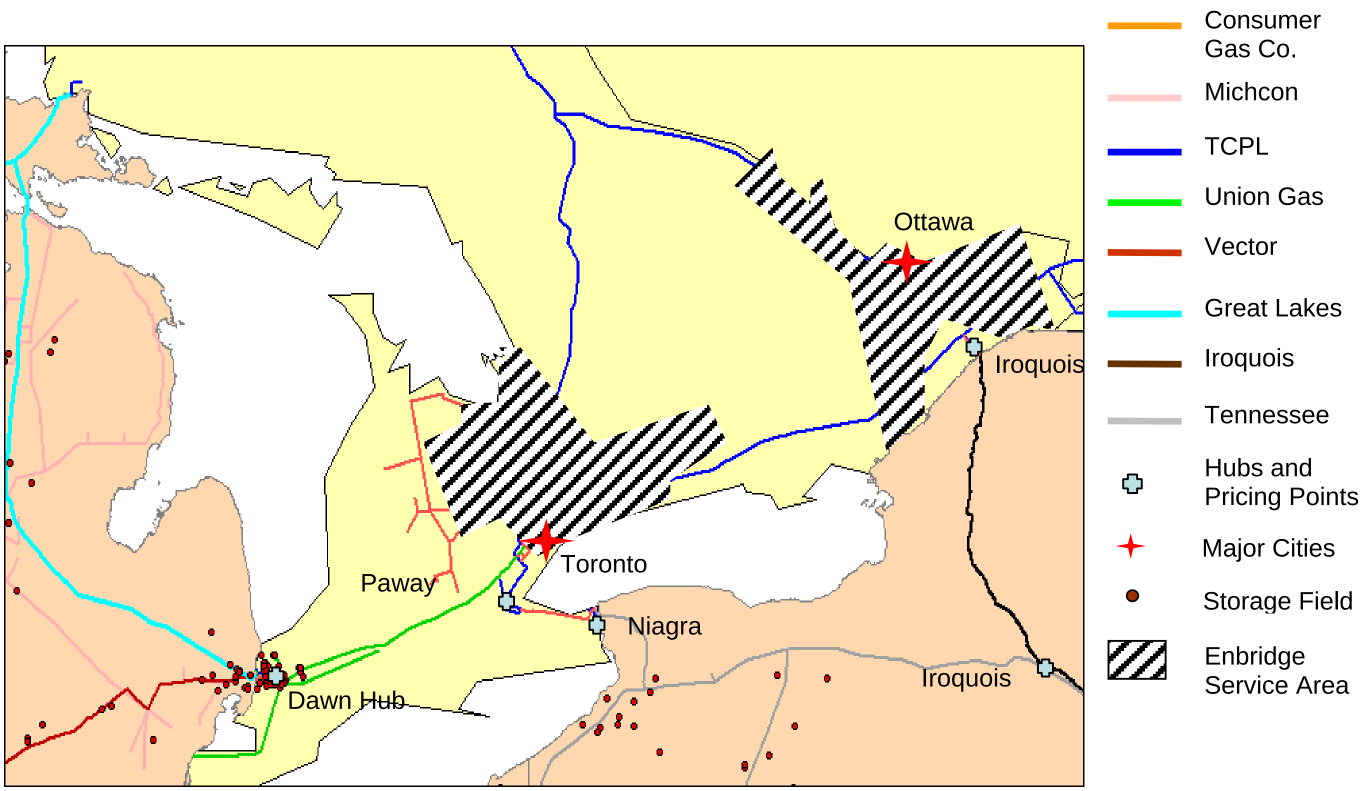
Union



Appendix 3

Map 3

Enbridge



Appendix 4: Evaluation of PBR Options

This section is structured as follows. First, the main approaches to PBR are discussed in greater detail. The options examined are rate caps, revenue caps, and benchmark regulation. These regulatory mechanisms are explained and evaluated for their relative merits. We then explore benefit sharing and plan termination provisions, two important features in each general approach to PBR.

A. Rate or Price Caps

Under a rate-cap plan, restrictions are placed on the terms of certain regulated services. Restrictions commonly take the form of limits on rate escalation. The limits are called caps since utilities are often free to charge rates that are less than the maximum allowed.

The mechanisms for determining allowed rate growth vary, but all are external. The simplest rate cap approach is to hold rates constant for the plan's duration. This is sometimes called a rate freeze or moratorium. A simple variant of the rate freeze is a set of pre-scheduled rate adjustments, which may be increases or decreases.

Another rate cap approach limits rate adjustments using indexes. Under this approach, growth in baskets of the utility's prices may be measured using APIs such as inflation indexes. Growth in each API is limited using a PCI. While the formulas vary from plan to plan, it is generally true that the price changes (ΔPCI) are based on the difference between an inflation factor (*P*) and an X-factor (*X*), plus or minus a Z-factor (Z). The standard rate, stated succinctly is a productivity factor that reflects projected cost savings and/or sales growth.

$$\Delta PCI = P - X \pm Z.$$

1. The Inflation Measure

The inflation factor, *P*, is the growth rate in an external price inflation measure. Three basic measures have been used in approved rate-cap plans. These may be constructively described as macroeconomic, industry-specific, and peer price measures.

Macroeconomic inflation measures are summary measures of growth in the prices of a wide range of the economy's goods and services. Those used in PBR plans are typically computed by government agencies. Examples include the chain-weighted price index for gross domestic product (GDPPI), consumer price indexes (CPIs), and producer price indexes (PPIs). Macroeconomic measures are almost universally used in telecom utilities' rate-cap plans. They are also the most common measures in plans for energy utilities outside North America. Indexes of consumer price inflation are used in most overseas indexing plans.

An important advantage of macroeconomic inflation measures is their simplicity. The measures also have credibility, since they are computed with some care by government agencies. The main concern with their use is that macroeconomic inflation measures may not closely input price inflation in utility industries because utilities are more capital intensive than the economy as a whole. Therefore, utility costs will be more sensitive to changes in capital prices than economy wide inflation indexes.

Industry-specific inflation measures are expressly designed to track inflation in the prices of the relevant utility inputs. Such measures are constructed using sub-indexes that track trends in the prices of major input categories. The weights assigned to the inflation sub-indexes reflect the percentage each input category represents in utility cost.

By design, an industry-specific inflation measure tracks industry input price fluctuations better than an economy-wide measure. By reducing business risk, industry-specific inflation indexes may allow companies and regulators to accept longer plan terms that, all else equal, enhance performance incentives.

One disadvantage of the industry-specific approach is its complexity. Another disadvantage is that there are no official sources of input price inflation for energy utilities. On the other hand, publicly-available data are available on inflation in individual input categories and have been used successfully to construct industry-specific inflation measures in several approved plans.

Peer price indexes are based on the prices charged by other service providers. For example, a peer price index for the bundled power service of a Midwestern utility might be constructed from the retail price trends of other Midwestern utilities. These indexes are appealing because they embody the input price and productivity trends of the industry, thereby avoiding controversy over how these trends should be measured. However, in North America, it is presently difficult to regulate most transmission and distribution services using peer price indexes due to the lack of unbundled price data.

2. The X-Factor

The X-factor is an external parameter in the PCI formula that typically causes the PCI to grow more slowly than the inflation measure. This benefits customers. The X-factor is sometimes called a "productivity factor" since productivity growth is sometimes explicitly involved in choosing its value.

The X-factor is typically established before a plan takes effect. Most commonly, its value in each plan year is set in advance and is constant throughout the plan. In some approved plans, X-factors are predetermined, but vary from year to year. The X-factor may also be recomputed at pre-determined intervals at the plan's outset. For example, the indexing plan for U.S. railroads updates the X-factor annually based on a rolling average of the industry total factor productivity trend.

3. The Z-Factor

The Z-factor adjusts the allowed price escalation rates for reasons other than inflation and productivity trends. It is likely to differ from period to period and may also differ across service baskets. One rationale for Z-factor adjustments is to recover from customers the effect that changes in government policy have on the company's unit cost of changes. Absent such adjustments, government officials can change policies in ways that raise the company's unit cost, confident in the knowledge that there will be little or no effect on rates. At the same time, some officials may neglect actions that would lower unit cost due, in part, to the belief that customers would not benefit.

Depending greatly on the plan details, price cap plans have the potential for enhanced marketing flexibility. Thus, price cap plans can potentially enhance a utility's marketing freedom since the allowed changes in regulated service rates are determined by an external mechanism. This reduces potential concerns with cross-subsidization that result when a utility's own unit cost data are used to set prices. Utilities can benefit from greater marketing freedom to enhance the market responsiveness of their rate and service offerings. Fewer marketing restrictions also allow diversification projects to be pursued in the most cost-effective manner, either through the utility or affiliated companies.

Price cap plans can also facilitate rate redesign and rebalancing. The rates that most North American utilities charge are not consistent with the known cost structure. This is especially true of the power transmission services and power and gas distribution services that have only recently been unbundled. Quite often, rates for energy distribution could be made more efficient by raising customer charges relative to usage charges and by implementing usage charges that reflect the time of use.

Although restructuring proceedings provide an opportunity to get rates “right” for wires and pipe services, practical considerations can prevent this from happening. An abrupt change in the rate design may be undesirable. Rate design considerations may also be a relatively low priority as the parties to the proceeding grapple with more pressing restructuring issues. Rate design changes may also redistribute cost responsibility in ways that are politically unpopular.

A rate-cap plan makes it possible to redesign rates for utility services gradually and automatically. A capped API can summarize the overall escalation in the prices of a service basket and adjustments in individual rate elements need not be restricted.[14] If an API for an energy distribution service is allowed to rise by 2%, for instance, it might be possible to raise the customer charge more rapidly than this if the volumetric charge rose less rapidly.

Some regulators may want to limit these rate design freedoms. For example, a common concern with respect to energy distribution utilities is that higher customer charges can disadvantage small-volume customers. In such a case, regulators may place conditions on allowed changes in certain rates or rate elements in order to protect certain customers or customer classes. For example, customer charges could be limited to the growth in the PCI plus 5%.

Rate rebalancing can also add to a utility’s marketing flexibility. Rebalancing occurs when some service prices grow more rapidly than the PCI and other service prices grow less rapidly. However, as with rate redesign, regulators may want to restrict rebalancing in order to protect affected customer groups. Rebalancing can be controlled with side conditions that limit the growth in prices for particular services, by reducing the scope of baskets, and by defining each service as a separate basket.

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14. Utilities can choose from among a number of alternative methods for computing the API of a particular service basket. Important criteria to use when selecting an appropriate API calculation methodology may include: 1) ease of computation; 2) the extent to which the API accurately measures the change in customer welfare from utility pricing policy; and 3) the extent to which a particular API method gives companies “credit” for discounts that may be allowed under the plan (discounts generally receive more weight in API calculations when the index accounts for consumption increases that result from price declines).

Market flexibility under rate-cap regulation also arises by introducing optional rates and services. These can be subject to light-handed regulation or, in the extreme, decontrolled completely. Several optional offerings may reasonably be considered such as: optional tariffs for regulated services, new services, unusually complex service packages, or services to competitive markets. Economists have found that price cap regulation can substantially mitigate the cross-subsidy concerns that arise with offering optional tariffs under COS regulation. This is because prices charged are not linked directly to costs, and utilities have no incentive to manipulate cost allocations in a manner that creates cross subsidies.[15]

4. Synopsis

Rate caps can generate utility performance incentives that are much stronger than those obtained under typical COS regulation, in part, because the PBR mechanism applies to both capital and operating costs of service. Incentives are, therefore, comprehensive so that a wide range of cost containment, product development, and marketing initiatives are encouraged. Another advantage over COS regulation is that indexing typically extends the period between rate cases. Improved unit cost performance will not reduce allowed price changes, at least until the plan is updated. An extended regulatory lag period should enhance productive and allocative efficiency.

Rate caps can provide a further boost to efficiency by relaxing operating restrictions. Consider, for example, marketing flexibility. To the extent that rate restrictions are external, monopoly service customers can be insulated from the effects of a company's operations in competitive markets. This reduces concerns about cross subsidization. Light-handed regulation of utility rates for non-core services is then possible. A company can also have more leeway in its purchases from affiliates and in its depreciation practices.

Rate caps also facilitate rate redesign. A wide range of rate element adjustments is consistent with a given rate of allowed price increase. A company will typically use these freedoms to move usage charges downward towards marginal cost. This should boost usage and reduce volume fluctuation risk.

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15. Ronald R. Brauetigam & John C. Panzar, *Diversification Incentives Under "Price-Based" and "Cost-Based" Regulation*, 20 RAND J. OF ECON. 373 (1989).

Rate caps can also reduce regulatory cost. Some startup costs must, of course, be incurred to master the new regulatory system. These may include closely monitoring the company's operations during the first indexing plans. But the frequency of future rate cases can be reduced substantially. Furthermore, reliance on external indexes diffuses inherently controversial cost allocation and transfer pricing issues. On the other hand, controversy can be considerable over alternative methods for measuring input price and productivity growth.

The numerous advantages inherent in rate caps are offset to some degree by disadvantages. One is regulatory risk. The length of the PBR contract can be put in play as regulators and governments change. Complexities often cause tinkering. An alternative is to set the term for a shorter period (*i.e.,* 3 years, not 5 years) and to make the formula simpler (*i.e.,* just adjust for inflation). Rate freezes or simple inflation adjustments are sensible alternatives to indexing in jurisdictions where regulatory risk is a concern but, this is not suitable in all times and places.

Rate caps also involve business risk, such as the possibility that price restrictions will not track trends in external business conditions that affect a company's unit cost. Relevant business conditions include weather, the business cycle, prices of competing energy products, and government policy. Windfall gains and losses may occur if the PCI does not reflect changes in these conditions.

Business risks can be mitigated through careful plan design and empirical research supporting key plan parameters. For example, an industry-specific inflation measure will track fluctuations in input prices better than a macroeconomic measure. An X-factor based on a regional rather than a national TFP trend may better reflect local economic activity. The Z-factor should reflect changes in government policy. An earnings-sharing mechanism can also mitigate business risk, as we discuss further below. However, some windfalls may occur even if the plan is well supported and designed. Ironically, this is another way in which rate-cap plans mimic competitive markets.

B. Revenue Caps

Revenue caps come in two flavors: (1) comprehensive; and (2) non-comprehensive. Under a comprehensive revenue cap, indexing formulas apply to a company's revenue, not its rates. Adding a balancing account mechanism can ensure that actual revenues are similar or equal to the revenue requirement. The balancing account contains any mismatch between actual and allowed revenues until rates can be adjusted to eliminate the mismatch. This is sometimes called a revenue-decoupling mechanism because it severs the link between revenue and efforts to market regulated services.[16]

Allowed changes in revenue are typically set using index formulas that feature an inflation measure, an X-factor, and a Z-factor. Compared with the rate indexing formula presented earlier, a growth rate formula for a revenue cap index requires some adjustment to reflect the effect of output growth on cost. An explicit term for such an adjustment may be called an output factor, which is denoted by *Y*. An index-based restriction on revenue requirement growth may then be written:

$$\Delta\ \mathit{Revenue\ Requirement} = \mathrm{P} - \mathrm{X} + \mathrm{Y} \pm \mathrm{Z}\ .$$

The X and Y terms, as here described, are sometimes captured in a consolidated X. If *X* happens to be similar to the expected growth of output (*i.e.*, $Y = X$), the formula can be simplified to:

$$\Delta\ \mathit{Revenue\ Requirement} = P \pm Z\ .$$

Some revenue cap indexes therefore do not contain X or Y factors. Because of these practices, X-factors from revenue cap plans must be used carefully when comparing plans. Some plans restrict growth in revenue per customer. This is equivalent to revenue requirement indexing where the growth rate in the number of customers is the output factor.

Like price caps, comprehensive revenue caps can create strong incentives for cost containment, which promote efficiency and eventually inures to customers' benefit. Both approaches are comprehensive and encourage efficiency in both capital and O&M costs. Both mechanisms also extend regulatory lag. The length is a tradeoff between incentives and the political need to bring some benefits to customers. Plans usually have incentives for a wide range of cost containment initiatives. The external basis for the revenue cap also encourages some operating flexibility.

A company under revenue cap regulation is also more likely to face greater restrictions on developing market responsive rates and services. If the plan includes a

16. Decoupling mechanisms have also been used in the absence of indexing. Prominent examples include the electric revenue adjustment mechanisms that have been used in California and Maine.

revenue decoupling mechanism, incentives to improve marketing performance, and thereby increased revenues are clearly compromised. For example, moving volumetric charges towards marginal cost will increase consumption, raise total revenue, and prompt rate reductions for other services. Marketing incentives may, therefore, be even weaker under revenue caps than under COS regulation.

Service quality concerns are also often exacerbated under revenue caps. As with price caps, service quality may suffer because there are strong incentives to cut costs. Rate and revenue caps create the same incentives to minimize costs but, under the latter approach, companies can use the balancing account to recover revenues that may be lost if poorer service quality leads to lower sales. This is not possible under rate caps. Consequently, the incentives to maintain service quality are weaker under revenue caps.

Revenue indexing can permit some reduction in regulatory costs relative to COS regulation. However, regulatory cost is likely to be somewhat greater than under rate indexing due to the costs associated with implementing and monitoring balancing accounts and the likely continued need to approve the revenue requirements allocation between customer groups, service offerings, and rate elements.

One advantage of revenue caps is that revenue decoupling mechanisms reduce windfall gains and losses that occur due to demand fluctuations. This stabilizes company earnings and can thereby lower capital cost. However, in the process, revenue decoupling destabilizes rates. For example, a recession in the service territory can place upward pressure on rates.

Decoupling also strengthens incentives to promote energy conservation, an important goal in many jurisdictions. However, there are other methods to promote energy conservation, such as targeted incentive plans for demand-side management. Such an incentive mechanism can be used to achieve conservation objectives without revenue caps' negative implications for allocative efficiency as revenue caps.

Revenue caps can also be non-comprehensive. Non-comprehensive revenue caps adjust only a portion of the company's rates or revenue requirement. An example is a cap on the revenue requirement (allowed cost) for O&M expenses. As with comprehensive revenue caps, partial revenue caps are usually developed using indexes, which will require an adjustment for output quantity growth.

Partial indexing plans typically do not address rate and service offerings. Utilities, therefore, typically require authority outside of partial rates and revenue caps to alter these offerings. Designing a partial revenue cap index usually involves choosing *the* inflation measure, X-factor, and Z-factor. The inflation measure in a revenue cap index for energy procurement would presumably be sensitive to changes in energy prices.

Non-comprehensive revenue caps can substantially externalize revenue requirements in the targeted areas. The full degree of externalization depends on other plan provisions, including plan termination, and benefit sharing measures. The approach can focus management attention on specific problems and promote performance improvements in the targeted areas. A partial indexing approach is also useful where there is consensus to use PBR for only certain areas of the company's business. If the scope of regulation is changing, for instance, plans may be designed to focus only on areas subject to continuing regulation.

One potential problem with partial revenue caps is that performance incentives are not comprehensive or balanced across cost components. There will, at a minimum, be no special incentives to market or to control cost in non-targeted areas. At worst, the company may be given an incentive to improve performance in the targeted areas at the expense of performance in other areas. For example, if a utility were subject only to a cap on O&M revenue, excessive capital spending could be undertaken to reduce O&M expenses. Overall, the company's performance might not improve.

This problem is mitigated to the extent that the partial caps cover most areas of controllable costs. However, plans approved to date have typically not been extended to cover major capital additions. This has been more of a political/regulatory choice, not a conceptual limitation.

By itself, partial indexing approaches do not improve allocative efficiency relative to COS regulation because they do not typically provide for pricing and marketing flexibility. Partial indexing also does not create strong incentives for aggressive product development and marketing. Because many aspects of COS regulation will remain, when partial indexing is implemented, this approach is also less likely than other PBR mechanisms to reduce regulatory costs. This will be particularly true for indexing mechanisms that apply to relatively small shares of regulated cost.

C. Benchmark Regulation

Benchmark regulation involves evaluating one or more indicators of company activity using external performance standards (benchmarks). The standards are external to the extent that they are insensitive to the actions taken by the subject utility's managers. Evaluations and rate adjustments are accomplished by formal mechanisms that are established in advance and typically function for several years.

A benchmark plan's key features are the performance indicators, the performance benchmarks, and the rate adjustment mechanism. The performance indicators used in approved benchmark plans vary greatly in scope. Plans are comprehensive to the extent that they cover all utility performance dimensions that matter to customers.

The performance benchmarks used in benchmark plans are also varied. A common benchmark is a company's activity level in a period just prior to plan commencement. A company is rewarded for improvement in its performance relative to its recent history. An alternative approach is to use the corresponding performance indicator of a group of utilities, which can consist of all utilities in the same region as the company subject to the plan. This is known as "yardstick regulation" or statistical benchmarking. The peer group may be viewed as a proxy for the regional industry. In principle, the region can also be the entire nation.. Under this approach, a company is rewarded for improving its performance indicator relative to the "peer" group.

The rate adjustment mechanisms in approved benchmark plans vary. A major design issue is the customer sharing percentage. The mechanism may or may not feature a deadband where deviations from the benchmark do not induce rate adjustments. Benchmarking plans usually provide supplemental adjustments to rates, rather than serving as the sole basis for rate adjustment restrictions. Several rate adjustment mechanisms can, in principle, coincide with a benchmarking plan. At one extreme, rates may be adjusted for the actual trend in a company's unit cost. At the other extreme, rates may be predetermined for several years.

As with revenue caps, there are both comprehensive and non-comprehensive benchmarking plans. A comprehensive benchmark plan is one in which benchmarking mechanisms cover substantially all facets of company performance that matter to customers. Comprehensiveness can be achieved by having many indicators that cover separate performance dimensions, or by having fewer broadly focused indicators.

Retail price indexes, unit cost indexes, and TFP indexes are examples of broad-based performance indicators. A basic unit cost index is the ratio of total utility cost to a utility output quantity index. Unit cost indexes can also rigorously incorporate additional utility performance dimensions that may influence customer welfare. These include service quality, environmental degradation, and conservation. Conceptually, a benchmark plan with such a “master index” can be separated into a plan with a set of consistent non-comprehensive performance variables and associated weights. Decomposing a master index in this manner does not affect its incentive properties.

The following two relations detail the relationship between the award mechanism and the primary rate adjustment mechanism:

$$\Delta PNDX^{award} = \alpha \cdot (\Delta UCNDX^{external} - \Delta UCNDX^{company})$$

$$0 \leq \alpha \leq 1.$$

Here $\Delta PNDX^{award}$ is the adjustment in the utility’s output price due to the award. It is proportional to the difference between the growth rates in $UCNDX^{external}$ (a unit cost index benchmark) and in the unit cost index of the company. The award rate, α, may assume a value between zero and unity. Thus, it determines the share of the measured performance improvement that is kept by the utility. If α = 1, the utility keeps all of the benefits of improving its performance relative to the unit cost benchmark. If α = 0, the utility keeps none of the benefits.

Now assume that other than the award mechanism, the change in a company’s rates is equal to the growth in its unit cost. The change in a company’s price index would be:

$$\begin{aligned}\Delta PNDX^{company} &\cong \Delta UCNDX^{company} + \alpha \cdot (\Delta UCNDX^{external} - \Delta UCNDX^{company}) \\ &\cong \alpha \cdot \Delta \cdot UCNDX^{external} + (1-\alpha) \cdot \Delta \cdot UCNDX^{company}.\end{aligned}$$

The authorized or allowed inflation in a company’s output price index ($PNDX^{company.}$) is approximated by a weighted average of the inflation in its unit cost index and in the external unit cost standard. The weights assigned to each category depend on the award rate. If α = 0, change in output price is approximated by the inflation in a company's unit cost. This may be termed "cost plus" regulation. If α = 1, output price escalation is approximated by the growth in the external unit cost standard. This is a form of rate indexing.

The plan described in these relations places a utility on a continuum between a variant of COS regulation (one without prudence reviews) and a variant of index-based regulation ("pure" price caps without discounting). That is, comprehensive benchmarking regulation provides an opportunity to move "part way" towards rate indexing.

Comprehensive benchmarking has the potential to strengthen utility performance incentives relative to COS regulation with short rate case cycles. Incentives are potentially balanced and comprehensive so that companies are guided to pursue the most promising performance improvements. For instance, companies can work to beat a unit cost or productivity benchmark through old-fashioned cost cutting or aggressive marketing to boost usage.

Comprehensive benchmarking can also help to extend the period between rate cases by sharing actual performance deviations from targeted performance using an automatic mechanism. This reduces regulatory and business risk in a manner that may predispose interested parties to agree on longer periods between plan reviews. The reduction in risk is, of course, valuable in its own right.

The actual effect of comprehensive benchmarking on performance incentives depends on plan details. The other provisions for rate adjustments are especially crucial. Incentives are weakened to the extent that other rate adjustment provisions involve regulatory discretion because regulators with discretion can respond to large performance awards by taking a tough line on other rate adjustments. A company will consider such actions as expropriating benefits that reduce its incentive to boost performance. Another plan detail with important incentive consequences is the sharing formula between the company and customers. Incentives weaken as the customer share rises. However, incentives can be strengthened relative to COS regulation if the benchmarking plan extends the period between rate cases.

Comprehensive benchmarking can, however, reduce regulatory cost and ease inefficient restrictions on operating flexibility. Sharing performance gains under a benchmarking mechanism can, nevertheless, raise cost allocation and transfer pricing issues. Resolving these issues can raise regulatory cost and may lead to operating restrictions. Comprehensive benchmarking also does not, by itself, allow for rate redesign or introduce new rates and services.

Non-comprehensive benchmark plans are similar in many respects to comprehensive benchmark plans. They also involve performance indicators, performance benchmarks, and award mechanisms. The main difference is that a non-comprehensive benchmark plan does not cover all dimensions of company performance.

Traditionally, many approved benchmark plans for energy utilities have been markedly non-comprehensive insofar as they feature a few narrowly focused performance variables. For electric utilities, indicators measuring fuel procurement, generator management, and demand-side management (DSM) have also historically been common. In a 1986 survey on incentive regulation, Joskow and Schmalensee identified forty-three generator performance plans in nineteen states.[17]

In the gas distribution industry, there are numerous approved benchmarking plans for gas procurement cost. Designing gas supply benchmarking has been challenging. Frontier issues include transportation cost and providing incentives for gas cost stability.

Probably the most important set of non-comprehensive benchmark mechanisms are service quality incentives (SQIs). These are SQIs are another form of benchmark regulation that rewards or penalizes a utility depending on the relationship between its measured service quality and quality benchmarks. There are three basic elements in an SQI plan: (1) a series of indicators of the company's quality of service; (2) an associated set of service quality benchmarks and; (3) an award mechanism that leads to changes in utility rates.

The indicators are measurable service quality dimensions; the benchmarks are the standards against which the indicators are judged. The benchmarks can be based on the company's historical performance, industry norms, or levels that are deemed to be acceptable.

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17. Paul R. Joskow & Richard Schmalensee, *Incentive Regulation for Electric Utilities*, 4 YALE J. ON REG. 1 (1986).

A quality assessment results when the service indicators are compared to the benchmarks. This is often determined simply by subtracting the benchmarks from the measured indicators. If actual service quality fails to meet the benchmark, then service quality has declined and a penalty may be warranted. Measured quality that exceeds the benchmark signals superior quality and a possible reward.

A quality valuation occurs when a quality assessment is linked to a change in utility rates of return. An award mechanism determines the adjustment in rates that is warranted by the change in service quality. Important design issues include the symmetry of awards and penalties and the customers' valuation of specific quality indicators.

Three criteria are important for selecting quality indicators. First, quality indicators should be linked to utility services that customers actually value. Second, some quality indicators should focus on utility activities for which there are few if any competitive alternative suppliers. This reflects the principle that regulation is less necessary in competitive markets. Market forces are likely to deliver acceptable quality levels when customers can choose among suppliers.

Third, utilities should be able to influence the measured quality performance through their own behavior. It does not make sense to link shareholder rewards or penalties to outcomes that do not reflect management actions. Quality dimensions that can be affected by random or unforeseen events beyond management control should be eliminated from the measured indicators. For example, reliability indexes can exclude power outages that result from severe storms.

Quality benchmarks are the standards against which measured quality is judged. It is also common to have "deadbands" around the benchmarks, or a zone within which utility performance is neither penalized nor rewarded. As with the quality indicators, some basic criteria can be used to evaluate choices for quality benchmarks and deadbands.

One important criterion is that benchmarks should be measured on the same basis as the quality indicators. If the data used to measure quality are not comparable to those used to set the benchmark, a company can be subject to arbitrary penalties and rewards. The SQI plan will be unworkable in that it will not be possible to determine how the utility's performance compares to the benchmark. Therefore, there will be no basis for determining whether to penalize the utility.

Benchmarks and deadbands should also reflect external business conditions in a utility's service territory. External business conditions can be defined as factors that can affect measured quality performance but are beyond the control of utility management control. Relevant factors include weather, the degree of ruralization in the territory (typically increasing response times to customer calls for on-site service), the mix of residential, commercial, and industrial customers, poverty levels, the heterogeneity of languages spoken, the growth rate in customer numbers, customers' tendency to relocate, and regulatory changes such as a industry restructuring to promote competition. Such factors differ across companies and may change over time for each individual company. Some are volatile in the sense that they are prone to fluctuations that are hard to predict.

Failing to control for these business conditions can also expose utilities to arbitrary penalties and rewards. For example, consider a SQI plan where a utility is rewarded or penalized depending on how its measured quality compares to that of another utility. Assume that both companies measure every quality indicator in the same way. This plan would still lead to unreasonable penalties or rewards if one utility had a more demanding service territory (*e.g.*, more severe weather). Not controlling for the effect of business conditions in that service territory would tend to handicap the utility serving that territory and, over time, lead to penalties that did not reflect its real quality performance.[18]

Third, benchmarks should be as stable as possible over the term of a SQI plan. Stable benchmarks give utility managers more certainty over the resources they must devote to providing adequate service quality, as reflected in those benchmarks. It is harder for managers to hit a "moving target," particularly if operational changes can only

18. For example, suppose the company in the more demanding territory really had worse service quality performance than the other firm in a given year; this SQI plan would lead to penalties both for worse performance *and* because one firm had more demanding conditions that made it more difficult to provide the same level of service as the other firm. In principle, a firm in a more demanding territory could also have better service quality performance and yet still register worse measured quality performance because of the impact of its more demanding business conditions. Here, the company is penalized even though it is a superior performer. In both cases the company's penalties do not reflect its real quality performance unless adjustments are made to the SQI plan to reflect differences in the companies' service territories.

be implemented over longer periods. Stable benchmarks therefore promote more effective, longer-term service quality programs.

In some cases, however, a lack of data available at the outset of a SQI plan may make it more difficult to set benchmarks that are viewed as reliable over the term of a multi-year plan. This would be true if the information systems used to record quality data had changed recently or if there was little confidence that a short data series reflected typical external business conditions for the utility. In such cases, benchmarks can be updated using data that become available during the term of the previous SQI plan. However, this should be done according to well-defined rules that are established at the outset of the plan. An example would be a benchmark equal to a ten-year moving average of a company's historical performance or an indicator if insufficient data is available, until 10 years of historical data are available. Setting benchmarks according to such objective rules creates as much stability as is feasible given data constraints.

The final element in an SQI plan is the mechanism used to reward or penalize the utility for its service quality performance. A penalty/reward mechanism accomplishes this by linking a quality assessment to a change in utility rates or allowed returns. A quality assessment relates quality as measured by the indicators to the quality benchmarks. In general, measured performance that 'exceeds' the benchmarks signals superior quality and a possible reward. Performance below the benchmarks indicates sub–standard quality and a possible penalty.

Important design issues for a penalty/reward mechanism include: (1) whether the mechanism is symmetric and allows for both rewards and penalties, or asymmetric and penalty–only; (2) whether award rates for individual quality indicators are based on estimates of the costs incurred to change quality or the value of quality changes to customers; (3) how individual award rates are set; and (4) the caps placed on maximum penalties and rewards. We discuss each in turn.

A basic issue that a regulator must decide is whether the award mechanism will be symmetric (both rewards and penalties are possible) or asymmetric (penalty–only). Some aver that only asymmetric service quality plans are appropriate. Proponents of this view contend that, in price or revenue cap regulation, service quality incentives are designed to prevent quality declines that may result from the incentives to reduce costs. Penalties are sufficient to deter such behaviour and rewards are, therefore, unnecessary. Some argue further that utilities benefit through cost reductions and marketing freedoms allowed under price caps, and additional rewards through quality incentives are too generous to shareholders.

However, a strong case can be made that symmetric incentive plans are more appropriate. Incentive regulation is intended to encourage superior performance up to the point where consumers' marginal valuations equal marginal costs, not simply to prevent performance from slipping. Since just and reasonable prices and the quality of service are both important to customers, symmetric service quality plans are needed to create incentives that improve performance in all areas valued by customers. Symmetric plans are also more consistent with behaviour in unregulated markets than are asymmetric plans. Customers in competitive markets routinely pay higher prices for higher quality products, and a symmetric service quality incentive reflects this phenomena. Competitive markets usually offer an array of goods with varying quality levels, and not all customers choose to consume high quality goods. When incentive plans lead to price increases on monopoly services, at least some customers may be paying for quality improvements that they do not want.

D. Benefit Sharing Provisions

A well-designed incentive or PBR plan should create stronger performance incentives with fewer operating restrictions than COS regulation. Performance is expected to improve under such a plan, and utilities can earn more while their customers pay less than they would have under COS regulation. The details of a PBR plan will influence how plan benefits are allocated between utilities and their customers. Consequently, the proper mechanism for sharing plan benefits is a controversial issue in many PBR proceedings.

Appropriate benefit-sharing provisions allow *both* shareholders and customers to be better off than they would have been under standard COS rate regulation. If PBR is voluntary, utilities have little incentive to agree to a plan unless it offers a reasonable chance for higher earnings, especially when faced with the higher risk entailed. It is wrong-headed to point to higher utility earnings as evidence that PBR has "failed."

Higher utility earnings are consistent with successful PBR (and the utility's higher risk) as long as customers also benefit compared to continuing the *status quo* COS regulation.

Selecting a benefit sharing mechanism should be based on sensible criteria. The primary aspects of the sharing mechanisms are: (1) performance incentives; (2) cross-subsidization and; (3) risk reduction. Simplicity and "salability," (*i.e.*, the ability to convincingly demonstrate benefit sharing) are also important.

Three benefit-sharing provisions that may be used under various approaches to PBR: (1) stretch factors; (2) adjustments to initial rates; and (3) ESMs. ESMs can also be viewed as a stand-alone form of PBR, although it is more common for earnings sharing to be a component in a broader PBR reform package.

The "stretch factor" is a component of the X-factor. The X-factor in a rate or revenue-cap index influences the allowed rate or revenue escalation. A higher value for X benefits customers of regulated services. An X-factor designed in accordance with classic North American principles is calibrated to reflect the relevant industry's TFP trend. Thus, one way to share expected plan benefits with customers is to set the X-factor above the calibration point. This is often called a stretch factor. It is set in advance to help ensure an external character for X. However, it can be allowed to vary from year to year.

Stretch factors were used in the initial price cap plan approved by the FCC for AT&T. A "consumer dividend" of 0.5% was added to the calculated TFP differential of 2.5% to yield an X-factor of 3%. Since then, stretch factors have been featured in many U.S. indexing plans. They are sometimes explicit and sometimes implicit in choosing an X-factor.

Stretch factor values can be assigned independently of a company's unit cost growth during the plan. By so doing, they do not compromise performance incentives or raise cross-subsidy issues.

Some critics have argued that regulators cannot commit to a stretch factor policy for subsequent plans. Absent such commitments, parties might reasonably expect stretch factors in future plans to reflect the utility's unit cost in the current plan. However, the brief history of North American price cap regulation does not provide much evidence to support this concern.

To the extent that they are external, stretch factors are not useful in reducing business risk. For example, applying a stretch factor may give customers a 0.5% break in rates even if the company's earnings were depressed by mild weather and a regional recession. As for regulatory risk, the short history of North American price cap regulation provides few clear lessons. Critics argue that stretch factors lack the solid foundation in economic research possessed by unit cost calibration points. Regulators' ability to assign values for stretch factors arbitrarily exacerbates the risk. On the other hand, the range of explicit stretch factor values that have been approved is actually fairly narrow. Nearly all have fallen in the 0% to 1.0% range.

Stretch factors are appealing to regulators insofar as they represent an advance commitment to customer benefits, which increases their salability. Customers benefit whether or not performance improvements are realized, even though they may not understand that stretch factors are designed to be insensitive to a utility's current earnings, and may resent high earnings if they occur.

A second important approach to sharing plan benefits is to lower the initial (base year) rates or revenue requirement below the levels that would otherwise result. When this is done, consumers immediately benefit. Moreover, benefits continue to be created in subsequent years since, with lower initial rates, lower prices result from index-based rate adjustments. This approach has been more widely used in the U.K. than in North American PBR to date.

The advantages and disadvantages of initial rate cuts as a benefit sharing mechanism are similar to those for stretch factors. Provided that the magnitude of rate cuts does not depend on actual unit cost improvements, performance incentives are strong. Cuts at the outset of an initial PBR plan are not problematic. The concern is, instead, with rate cuts that are imposed when PBR plans are updated and are linked to actual performance gains under PBR. Performance incentives are weakened as this linkage becomes more direct and explicit. As with stretch factors, initial rate cuts do not mitigate business risk and can actually increase regulatory risk absent a proper conceptual and empirical foundation. Customers benefit whether or not utility performance improves, but may resent high earnings if they occur.

Initial rate adjustments result in immediate benefits to consumers. However, it is difficult to demonstrate that rate cuts are, in fact, being made when companies propose rate increases just prior to indexing. Utilities are forced to claim that they could have asked for even larger price increases and that customers have benefited from the company's restraint. Since other parties will have differing opinions about whether any increase is warranted, the benefits may be less convincing.

The third important approach is an ESM that adjusts a company's prices whenever earnings fall within a pre-established range. The mechanisms are established in advance and typically function for several years. The most widely-used earnings measure is ROE.

Approved ESMs vary significantly in several ways. The most important difference is the share of surplus (and/or deficit) earnings assigned to shareholders and customers. These shares may change in different ranges of the ROE. Many plans feature a range (called a deadband) in which rates are not sensitive to ROE fluctuations. Immediately beyond the deadband, the customer share is commonly 50%. In some plans, it increases substantially when ROE is extraordinarily high and falls substantially when it is extraordinarily low. Such plans are characterized by "regressive" sharing mechanisms. Alternatively, a "progressive" ESM reduces the customer's share of benefits as ROE increases. Some plans are symmetric in the sense that they provide for rate decreases when earnings are high and rate increases when earnings are low. Other plans provide for rate adjustments only when earnings are high.

ESMs have some important advantages as benefit sharing mechanisms. One advantage is their ability to mitigate risk. ESMs automatically adjust rates for a wide range of risky external developments. As an alternative to initial rate reductions and X-factors, ESMs also reduce regulatory risk. In effect, benefits are shared as they are realized and there is less pressure on regulators to choose stretch factors and initial rate reductions that share the (usually speculative) plan benefits. There is, however, some regulatory risk to the utility that the board will approve an asymmetric ESM in which earnings shortfalls are not shared.

In addition to risk management, another benefit of ESMs is their salability. Customers and their representatives can appreciate how an ESM aligns shareholder and customer interests. Benefits seem transparent and easily computed. ESMs will also keep utility earnings within politically acceptable bounds.

On the downside, ESMs do not, by themselves, guarantee that customers will benefit from a PBR plan. Customers may complain if distributor earnings exceed the target ROE but fail to reach the sharing range. Higher rates due to an earnings shortfall can be especially controversial.

Another disadvantage of ESMs is that there will be continued attention to inherently controversial issues like utility-affiliate transactions, cost allocations, and similar factors that can affect measured earnings and, accordingly, the amount of earnings to be shared. Attention to these issues can discourage efficient diversification and impose undue regulatory costs. Utilities will become more sensitive to the problems associated with ESMs as they seek to realize potential scale and scope economies from simultaneous involvement in regulated and competitive markets.

ESMs' effect on performance incentives is controversial. Compared to a multi-year rate-cap plan where rate restrictions are completely insensitive to a utility's performance, a plan with an ESM weakens a company's performance incentives because, utility managers have less incentive to improve performance if half of the after-tax benefits go to customers. On the other hand, the various advantages of ESMs may permit the interested parties to agree to extend the period between plan reviews. Longer regulatory lag periods improves incentives. ESMs may also help the parties agree to plan termination provisions that can have positive incentive consequences.

ESMs typically increase regulatory costs during periods where companies are not otherwise subject to regulatory intervention, such as a multi-year rate plan. For example, it may be necessary to compute the cost of regulated services, and therefore to allocate total cost between regulated and unregulated services.[19] However, if ESMs extend the period between general rate cases, at least some of these regulatory costs may be offset.

19. This is a major concern for telecom utilities, which typically provide extensive regulated and unregulated services from the same facilities.

E. Plan Termination Provisions

Plan termination provisions are increasingly important. One important consideration here is simply the PBR plan's term. Provisions for resetting rates when the plan ends are also important.

The trend in PBR has clearly been towards longer-term plans. Three-year plans were typical during the 1990's. More recently, five-year terms have become standard, and some plans have been approved with considerably longer terms. Prominent examples are the ten-year plans for power distribution services of National Grid in Massachusetts and New York, and the ten-year plans for the gas distribution service of Berkshire Gas and Boston Gas, both in Massachusetts.

Longer plan terms strengthen performance incentives and alleviate concerns about cross-subsidies and novel operating practices that can lead to operating restrictions. Longer terms are especially useful in encouraging initiatives that involve up-front costs to achieve long-run efficiency gains. That is one reason why longer plan terms are often approved for utility mergers. Both National Grid plans mentioned above involved mergers.

On the downside, longer plan terms can increase both business and regulatory risk. This makes them less suitable for businesses undergoing rapid business and regulatory change. The risk of a longer plan term can be reduced by several other plan provisions, including industry-specific inflation measures, Z-factors, marketing flexibility, and ESMs.

Similarly, the rate reset provisions of PBR plans vary widely. At one extreme, the plan may include a provision for a full-scale cost-based rate or revenue requirement true-up at the end of the plan. At the other extreme, a plan could be reset based entirely on external data. For example, a rate or revenue cap index could be revised only to better reflect the industry's recent unit cost trend.

The rate reset provisions in most PBR plans for energy utilities lie between these extremes. The most common approach is to not specify how rates might be reset. An interesting alternative is that, in the event of a cost-based rate true-up, utilities will be entitled to keep some of the demonstrable benefits associated with superior performance.[20] Plans with this innovative feature have included those for National Grid's power distribution services and for power distributors in Victoria, Australia. The latter plan employs an "efficiency carry over" mechanism.

Rate reset provisions are important because they affect the externalization of the regulatory mechanism. To the extent that a full cost-based rate true-up is avoided, performance incentives are strengthened and there are reduced concerns about cross subsidies and novel practices that can lead to operating restrictions. Incentives for initiatives involving up-front costs and long term benefits are, once again, especially affected. On the downside, rate plans that do not call for a full cost-based rate reset involve greater risk. As in the case of longer plan terms, a variety of other mechanisms are available to mitigate this risk.

20. In principle, they might also be asked to share the losses from demonstrably inferior performance.

Appendix 5: Survey of PBR in North America and the U.K.

This section addresses PBR precedents from the U.S .and U.K. where different approaches have been taken towards calibrating the terms contained in indexing plans. The U.S. PBR precedents are much more varied than those in the U.K.

A. Price Cap Regulation

Two countries have extensive experience with price cap regulation: the U.S. and the U.K. A method for *PCI* design to be used in rate cap regulation has been established in both countries, but the approaches differ greatly. Surprisingly, the differences are poorly understood on both sides of the Atlantic. Below we explain the U.S. and U.K. approaches to *PCI* design and discuss salient X factor precedents in both countries.

1. U.S. Approach

Although many associate rate indexing with the U.K., the U.S. actually has a longer history with this regulatory system. The most common U.S. approach to *PCI* design was outlined in a 1979 paper by E. Fred Sudit of Rutgers University.[21] [22] William Baumol, then at Princeton University, elaborated on the idea in a 1982 paper.[23] The U.S. approach to *PCI* design was influenced by these early treatises, but credit must also go to regulators in early regulatory proceedings and supporting legislation.[24]

The U.S. approach to *PCI* design is based on the premise that utility regulation should mimic competitive markets. The trend in the prices charged by a competitive industry is the trend in its unit cost. Productivity growth benefits are then passed to customers over time through slower price growth. Because the *industry* unit cost trend is insensitive to individual firm actions, companies in competitive markets have strong incentives to slow unit cost growth.

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21. E. Fred Sudit, “Automatic Rate Adjustments Based on Total Factor Productivity Performance in Public Utility Regulation”, in *Problems in Public Utility Economics and Regulation* ed. M. Crew, Lexington Books, 1979.

22. Sudit subsequently collaborated with Michael Crew and Paul Kleindorfer on an alternative approach to index based regulation that has not to our knowledge been implemented. In this approach, the utility nominates the X-factor that is used in the plan. A mechanism is proposed that incents the company to base its nomination on its TFP growth expectation.

23. William J. Baumol, “Productivity Incentive Classes and Rate Adjustment for Inflation”, *Public Utilities Fortnightly*, July 22, 1982, pp. 11-18.

24. The earliest price indexing plans approved in the United States emerged from hearings before federal regulatory commissions in the 1980s. An indexing plan was first approved in 1981 for certain services of Class I railroads. This predates both Stephen Littlechild’s famous 1983 paper on the merits of RPI-X indexing and the first UK application of RPI-X regulation to British Telecom in 1984.

The logic behind this result is important. If an industry earns, in the long run, a competitive rate of return, the growth trend in an index of the prices it charges (its output prices) will equal its unit cost trend. The trend in an industry's unit cost is the difference between trends in its input price index and its TFP index.[25]

The TFP index above corresponds to that for the relevant utility industry. This is necessary for the allowed change in prices to conform with the competitive market paradigm. In competitive markets, prices change at the same rate as the *industry's* trend in unit costs and are not sensitive to the unit cost trend of any individual firm.

Industry TFP trends are necessarily estimated using the industry's historical data. Utility industries have historically been subject to rate of return regulation. Economists generally think that rate of return regulation does not create optimal incentives to contain unit cost. Thus, industry TFP and input price trends calculated from historical data will naturally reflect the industry's historical unit cost performance.

Rate indexing is designed to create stronger performance incentives than traditional regulation. Superior incentives should lead, in turn, to more rapid TFP growth relative to historical norms. Regulators recognize this, and rate indexing plans typically incorporate what are called either "consumer dividends" or "stretch factors" to reflect the expectation that TFP growth will increase under PBR, and consumer prices should reflect some of the benefits of this expected growth.

This analytical framework helps explain some major issues that are addressed in North American price indexing proceedings. The first is the industry TFP trend. The second is the success with which proposed inflation measure tracks industry input price inflation. The third is the appropriate benefit sharing mechanism, which will in most

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25. The full logic behind this result:

$$\begin{aligned}
\text{trend Unit Cost}^{\text{Industry}} &= \text{trend Cost}^{\text{Industry}} - \text{trend Customers}^{\text{Industry}} \\
&= \left(\textit{trend}\ \text{Input Prices}^{\text{Industry}} + \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&\quad - \textit{trend}\ \text{Output Quantities}^{\text{Industry}} \\
&= \textit{trend}\ \text{Input Prices}^{\text{Industry}} \\
&\quad - \left(\text{trend Customers}^{\text{Industry}} - \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&= \text{trend Input Prices}^{\text{Industry}} - \textit{trend}\ \text{TFP}^{\text{Industry}}.
\end{aligned}$$

cases involve choosing a value for the consumer dividend. The X-factor of the *PCI* can in principle reflect all three considerations.[26] [27]

a. U.S .Precedents

While COS regulation still holds sway in much of the U.S., several indexing plans have been approved for US energy utilities. Nearly all these plans have been approved in three states: California, Maine, and Massachusetts. Consistent with the US approach to CPI-X regulation, TFP evidence has been important in nearly all these approved plans. Below we discuss the main features found in price indexing plans for

- the comprehensive power services of PacifiCorp-California.

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26. For example, a consumer dividend can be added directly to the industry TFP trend so that the X factor is the sum of the industry TFP trend plus the consumer dividend. The logic involving terms that allow the inflation measure to track the industry input price trend better is somewhat more complex. Many firms use broad measures of economy-wide inflation, like the GDP-PI, as an inflation factor in indexing plans. If the trend growth in GDP-PI is both added and subtracted from the right hand side of equation [2] above, this equation is unchanged. Doing so yields the following formula

$$\textit{trend Unit Cost}^{\textit{Industry}} = \textit{trend GDPPI} - \left[\begin{array}{l} \textit{trend TFP}^{\textit{Industry}} \\ + \left(\textit{trend GDPPI} - \textit{trend Input Prices}^{\textit{Industry}}\right) \end{array}\right] \qquad [3]$$

The items in the bracketed term can be further decomposed by recognizing that the GDP-PI is a measure of *output* price inflation in the overall economy. Given the broadly competitive structure of our economy, the same indexing logic detailed in equation [1] and [2] will also apply to the measures of economy-wide output price inflation. This logic implies that the long-run trend in GDP-PI is the difference between the trends in input price and TFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{\textit{Economy}} - \textit{trend TFP}^{\textit{Economy}}\,. \qquad [4]$$

Substituting [4] into [3] implies that

$$\textit{trend Unit Cost}^{\textit{Industry}} = \textit{trend GDPPI} - \left[\begin{array}{l} \left(\textit{trend TFP}^{\textit{Industry}} - \textit{trend TFP}^{\textit{Economy}}\right) \\ + \left(\textit{trend Input Prices}^{\textit{Economy}} - \textit{trend Input Prices}^{\textit{Industry}}\right) \end{array}\right] \qquad [5]$$

If the GDP-PI is used as an inflation factor for the PCI, the bracketed expression corresponds to the X factor. This result shows that the X factor should be calibrated to reflect *differences* in the input price and TFP trends of the relevant utility industry and the economy. The productivity differential will be the difference between the TFP trends of the industry and the economy. X is more apt to be positive, slowing PCI growth, when industry TFP growth exceeds the economy-wide TFP growth embodied in the GDP-PI. The inflation differential is the difference between the input price trends of the economy and the industry. X will tend to be larger (smaller) when the input price inflation of the economy is more (less) rapid than that of the industry.

27. Some indexing plans also apply comprehensive indexes to revenues rather than prices. Rather than limiting the escalation in an index of utility prices, revenue caps limit revenue growth. A growth rate formula for a revenue cap index requires an adjustment to reflect the effect of output growth on cost. An explicit term for such an adjustment may be called an output factor and denoted by *Y*. An index-based restriction on revenue requirement growth may then be written

$$\%\,\Delta\,\textit{Revenue Requirement} = P - X + Y \pm Z\,.$$

Some plans restrict growth in revenue per customer. This is equivalent to revenue requirement indexing where the growth rate in the number of customers is the output measure, *Y*.

- the comprehensive power services of Central Maine Power (CMP).
- the power distribution services of CMP (after the Maine electric utility industry was regulated and competition introduced for power generation services).
- the power distribution services of SCE.
- the gas distribution services of Boston Gas.
- the power distribution services of SDG&E.
- the gas distribution services of SDG&E.
- the gas distribution services of Berkshire Gas (Massachusetts)
- The updated plan for Boston Gas

i. California

The first indexing plan for energy utilities in California was approved in late 1993 for PacifiCorp. The X-factor in this plan was based on the company's own long-run TFP trend. This TFP trend was computed by the Office of the Ratepayer Advocates (ORA), which is a part of the California Public Utilities Commission (CPUC). The initial X-factor was set at the company's long-term TFP trend of 1.4%. In 1997, this TFP trend was updated to include PacifiCorp's three most recent years of performance. The resulting X-factor was 1.5%. No consumer dividend was added to this long-run TFP trend when setting the X factor.

The first CPI-X regulation plan approved for a North American power distributor was SCE's. The plan used the U.S. CPI for its inflation measure. This plan took effect in 1997. The X factor in this plan rises from 1.2% in 1997 to 1.4% in 1998 and 1.6% in 1999-2001.

This X factor was based on a TFP study that SCE conducted of its TFP growth. This CPUC accepted the study, which showed SCE's 0.9% per annum long-term TFP growth trend. The overall X factor, therefore, reflects this TFP trend plus consumer dividends that rise from 0.3% to 0.7% over the plan's life, with an average 0.56% value.

In approving this plan, the CPUC stated it would have preferred to use industry TFP measures as the basis for the X factor. However, no party in SCE's preceding presented evidence on industry TFP. The CPUC espoused a competitive market standard as the rationale for its preferred approach. It wrote:

> The price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its own cost and productivity. The productivity measure should come from a forecast of industry specific productivity.[28]

SDG&E had first approved indexing plan for a combination utility, covering both gas and power distribution operations. Separate industry-specific inflation measures were constructed for both electric and natural gas services, reflecting inflation in capital labor and other O&M inputs. SDG&E presented evidence estimating annual industry TFP trends in the power distribution (0.68%) and gas distribution industries (0.92%). The CPUC accepted this evidence and added an average consumer dividend of 0.55% per annum to each plan. The average X factors for power and gas distribution were, therefore, 1.47% and 1.23%, respectively. Both plans are currently being updated but final decisions have not been reached in the proceedings.

ii. Maine

CMP presented TFP evidence has been presented in its two approved indexing plans. In both cases, the final terms of the indexing plans resulted from a settlement reached between proposals put forward by different parties.

The first CMP indexing plan grew out of a rate case that was brought before the Maine Public Utilities Commission in December 1992. In its final Order in December 1993, the Commission approved a modest rate increase, but also concluded that CMP's efficiency and cost-cutting efforts were inadequate. It directed CMP and other parties to develop a price cap plan that provided CMP with stronger incentives to operate efficiently.

The original CMP indexing proposal was presented in June 1994. CMP proposed to use an indexing mechanism to set rates for the 1995-99 period. The inflation factor was to be the change in the Consumer Price Index (CPI) for all Urban Consumers. No X factor would be applied in the first two years of the plan. The X factor in each year from 1997-99 would equal one-third of the CPI growth rate. Given projected inflation trends,

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31. Application of Southern California Edison to adopt a Performance Based Rate Making Mechanism Effective January 1, 1995, Alternate Order of Commissioners Fessler and Duque, July 21, 1996.

this would have created an X factor in these years of about 1%. The Commission deemed this X factor reasonable in light of TFP evidence CMP presented showing industry TFP growth in comprehensive power services that was slightly below 1% per annum. However, indexing would not apply to several important expense categories (DSM costs, restructured purchase power contracts and one-half of the costs related to a change in accounting procedures for post-employment benefits), which were to be treated as "Z factors," or items whose costs could be passed through directly to prices subject to regulatory approval of final costs.

Coincident with the CMP proposal, another price cap plan was developed by a consortium of interested parties. This plan became known as the Public Party/Customer Proposal (PPCP). Minor modifications to this plan were suggested by some groups, but the PPCP was essentially a consensus counterproposal that enjoyed broad support among Commission staff and major intervenor groups.

The PPCP featured the fixed-weight deflator for Gross Domestic Product (GDP-PI) as the inflation measure. The X factor increased over the term of the plan from 0.5% in 1995 and 1996 to 1.0% in 1997 and 1.5% in 1998-99.

The PPCP also contained a long list of Z factors. The items proposed by CMP were also recommended as Z factors in the PPCP. In addition, Z-factor treatment was to be afforded to deferring Electric Revenue Adjustment Mechanism (ERAM) balances, 50% of the margins from (FERC-regulated) bulk power, cost changes that result from variation in capacity factors at plants where CMP purchases power, and amortizations arising from CMP's cancelled plant.

In October 1994, a Stipulation was agreed to between CMP and the parties represented in the PPCP. This agreement resembled the PPCP more than the CMP proposal. However, the Stipulation modified certain PPCP plan components and contained several features that were not present in either proposal. The Commission approved this stipulation without modification, which we discuss below.

The GDP-PI was selected over the CPI as the inflation measure for three reasons. First, the GDP-PI is considered to more accurately reflect economy-wide inflation because it tracks prices for more goods and services. Second, the GDP-PI utilizes more recent data to weight individual service prices in computing the index.[29] Finally, the Commission concluded that the GDP-PI has been less volatile than the CPI in recent years.

The X factor was 0.5% in 1995 and 1.0% in 1996-99. These values were lower than had been proposed in the PPCP. The items to be afforded Z-factor treatment were essentially the same as that proposed by CMP.

The indexing formula was different than either party had proposed. CMP wanted the *PCI* to apply to the entire rate, while the PPCP applied the *PCI* to base rate changes only and set fuel rates through a complex system of fuel cost projections and reconciliations. In the final agreement, the *PCI* was applied to the entire rate but there was a "QF adjustment" to reflect the fact that some of CMP's purchased power costs were not sensitive to aggregate inflation trends. In practice, the QF adjustment was to be implemented by multiplying the change in the *PCI* due to the inflation, X and Z factors by (1-.375). The value selected for the QF adjustment was based on the Commission’s judgment that 37.5% of CMP's costs were not affected by inflation.

A somewhat similar outcome occurred in the power distribution plan that was approved for CMP in 2000. While CMP’s proposal featured TFP evidence, the plan’s final terms were reached in a stipulated agreement between most interested parties. The approved X factors ranged from 2% to 2.9% over the plan’s term. The Commission did not make any specific findings on the industry TFP trend. However, the X factors did incorporate productivity gains CMP was expected to realize from a merger that it recently completed.

iii. Massachusetts

A rate indexing plan was approved for Boston Gas in Massachusetts in 1997. The X factor approved for Boston Gas had four components: (1) a TFP differential (*i.e.*, the difference between industry and economy-wide TFP trends); (2) an input price differential (*i.e.*, the difference between economy-wide and industry input prices); (3) a stretch factor; and (4) an accumulated inefficiencies factor. The first two components

29. Both the GDP-PI and CPI are fixed-weight price indexes, where the weights that are applied to the prices of goods in the basket are based on expenditure patterns in a base year. The base year for the GDP-PI is currently 1987. For the CPI, the base year is currently the 1982-84 period.

reflect the indexing logic presented earlier when an economy-wide inflation measure was employed as the inflation factor. This was the case for Boston Gas, whose proposed inflation factor was the gross domestic product price index (GDP-PI), which is the official measure of GDP price inflation.

The Massachusetts Department of Public Utilities (MDPU) initially approved an overall X factor of 1.5%. The approved TFP trend for the gas distribution industry was 0.4%, which was a proxy for the trend in the regional gas distribution industry. The Commission agreed that the industry in the region (the Northeast United States) was distinct from that of the rest of the country due to evidence of different cost pressures in the Northeast. The *economy*-wide TFP trend was 0.3%, so the TFP differential between the industry and the economy was 0.1%. The input price differential was measured to be –0.1%. Input prices in the industry were therefore shown to be growing 0.1% less rapidly than economy-wide input prices. The sum of the TFP and input price differentials was therefore zero.

The approved consumer dividend was 0.5%. A fourth "accumulated inefficiencies" factor was also added that was equal to 1.0%. This factor has only been added in Massachusetts indexing plans, and it is designed to reflect accumulated COS regulatory inefficiencies. The MDPU first approved an accumulated inefficiencies factor of 1% in the indexing plan for the state's telecom utility, NYNEX-Massachusetts. Boston Gas subsequently appealed the accumulated inefficiencies factor to the courts, which agreed that the factor had no evidentiary basis and ordered the DPU to eliminate the factor. The final X factor in this plan was therefore 0.5%.

The industry TFP and input price evidence approved in the Boston Gas proceeding was later used in an indexing proposal by Berkshire Gas. Unlike Boston Gas, Berkshire Gas is a relatively small gas distributor. Berkshire Gas argued that it would not be cost effective for it to undertake a separate TFP study to support its X factor, and that the outcome of such a study would probably not differ dramatically from that presented by BoGas in any case. Berkshire Gas, therefore, took the zero value for the combined TFP and input differentials in the Boston Gas case as the starting point for its X factor.

The final X factor for Berkshire Gas also included a consumer dividend of 1%, bringing this plan's overall X factor 1%. While this is at the high end of approved consumer dividends in U.S. indexing plans, the Berkshire Gas plan does not contain an ESM, so it is reasonable for the value of the consumer dividend to be higher because it is the sole mechanism for sharing benefits with customers under the plan. In addition, the Berkshire Gas plan may be in effect for as long as 10 years, creating stronger performance incentives than most indexing plans that have terms between three and five years. All else equal, stronger performance incentives should lead to a greater acceleration of TFP under the indexing plan relative to the industry's historical norms. This, in turn, will support a higher value for the consumer dividend.

The most recently approved indexing plan in Massachusetts was for Boston Gas. The X factor formula was identical to that approved in the original plan, except for the elimination of the accumulated inefficiencies factor. The approved TFP trend for the Northeast gas distribution industry was 0.56%, the TFP trend for the U.S. economy was 0.77%, so the TFP differential was -0.21%. The input price differential approved by the Commission was 0.3%. The consumer dividend was 0.3%. The overall X factor was therefore 0.41% (-0.21% + 0.3% + 0.3% = 0.41%).

2. U.K. Approach

The British approach to *PCI* design is typical of utility rate regulation in the U.K. Most British utilities were formerly public enterprises and were subject to privatization sometime in the last twenty years. British Telecom (BT) was the first utility to be privatized, in 1984. Since then, privatization has extended to the nation's electric, gas, water utilities, and rail infrastructure.

The decision to use rate indexing in British utility regulation was strongly influenced by the recommendations of Stephen Littlechild of the University of Birmingham, in a report released in 1983.[30] He proposed to adjust BT's rates using an "RPI-X" formula. The RPI term is the inflation in the Retail Price Index (RPI). A specific value for X was not recommended, nor was there significant discussion in Littlechild's paper of the appropriate framework to be used to determine X. Rather, the value for X was described vaguely as "a number to be negotiated."

30. Stephen Littlechild, *Regulation of British Telecommunications' Profitability: Report to the Secretary of State*, February 1983.

The laws that privatized British utilities provided little guidance with respect to the basis for choosing X. Without a well-defined framework, British regulators had considerable discretion in determining X-factors. Over time, however, regulators for different utility industries have adopted similar approaches. This "British approach" can be illustrated by examining the manner in Regional Electricity Companies (RECs) are regulated in England and Wales.

a. Power Distribution

Five-year price cap plans were instituted for REC distribution prices upon their privatization in 1990. The terms of the plans were written into the authorizing legislation. Initial rates were set at the levels charged by the companies just before privatization, even though these rates presumably reflected inefficiencies under state ownership.

Different X-factors were established for each REC. These ranged from 0 to -2.5%, and had an average value of -1.3%. Therefore, RECs' distribution prices were allowed to *increase* by an average of 1.3% per annum in real terms during the five years of the first price cap plan. The reasons for allowing real price increases were not made explicit, but some sources indicate that it was motivated, in part, by a desire to give the companies funds with which they could refurbish networks and improve service reliability. In addition, the companies were being sold to private investors. The terms of the indexing plans were likely set, in part, to spur investor interest and maximize proceeds from the sale.

The distribution price cap plan was first reviewed in 1994. This review focused on four considerations when re-setting the X-factor: (1) operating expenses; (2) planned capital expenditures; (3) valuing capital stock used in power distribution; and (4) the allowed return on that capital stock. The regulator reviewed these factors by analyzing the RECs' cost and sales data and by soliciting independent evaluations of REC operations. For example, consultants provided opinions on "best practices" for different distribution functions, and outside analysts estimated network expansion costs given projected changes in the number and location of customers. Statistical benchmarking studies were undertaken to estimate the efficient operating cost level for individual RECs given various factors beyond management control. These included customers served, volumes distributed at low and high voltage, and customer density within the territory served. Although these benchmarking studies were undertaken, the results were not made public. Consequently, their role in the regulator's determination was not clear.

The methods used in this review clearly resemble COS regulation. In effect, the regulator determined revenue requirements for the utilities. These revenue requirements were based on the utilities' actual cost and assertions by them and other analysts regarding the "prudent" levels of various costs over the next five years. In the U.K. and elsewhere, this approach has been termed the "building block" method for updating RPI-X controls.

An important difference between the U.K.'s price cap review and a typical COS rate case is that indexing was used to extend the plan horizon substantially. Rates in the first plan year and the value of X were jointly chosen. Given projected sales volumes and RPI inflation, this would have generated revenue sufficient to cover the companies' operating and capital costs during the five years of the new plan.

The RECs distribution price control was updated again in 2000. This led to another initial price cut that varied between 19%, and 33% between companies. The X factor in the other four years remained at 3%. The methods used to update the control were very similar to those used in 1995, with two exceptions. First, there was more emphasis on econometric benchmarking, although the actual benchmarking results and their application in the controls were not transparent. Second, there were moves to strengthen the link between RECs' service quality and their financial performance.

The 2005 update of RECs' distribution prices is currently underway. The Office of Generation (Ofgem) is publicizing the results of benchmarking work it has undertaken and has commissioned research on TFP trends and benchmarking evaluations (using several techniques) for U.K. RECs. These reports are available on the Ofgem website.

b. British Gas/Transco

British Gas (BG) was a vertically-integrated natural gas services provider when it was privatized in 1987. In addition to having a near monopoly on British gas transmission and distribution services, it has extensive gas supply operations. The original BG price cap formula restricted the annual growth in gas delivery rates to inflation in the RPI minus 2%. The X-factor has since been updated to 5% (1992-94) and

4% (1994-97). The downward revision of X in 1994 coincided with a regulatory decision to expand the number of customers who were granted access to alternative gas suppliers. Since this expansion reduced BG's earnings, the X-factor was reduced accordingly.

The most fully articulated statement of the British approach towards price cap regulation is contained in the 1997 price cap plan for Transco (the gas transmission and distribution company created when BG was functionally unbundled). At least two factors make this a compelling precedent. One is that the regulator's methods for updating the plan were specified quite clearly. The second is that the approved plan resulted from an appeal of the regulator's recommendation to the Monopolies and Mergers Commission (MMC). The MMC has advanced a very detailed statement of the basis for the new price controls.

To determine the price controls for Transco, the Office of Gas Supply (Ofgas) took as a "starting point" a long term net present value (NPV) calculation. This calculation determined "a level of revenue which, when set against expected expenditure and discounted at the company's cost of capital, would produce a net present value (NPV) of zero".[31] In other words, Ofgas was attempting to determine a forward-looking revenue requirement that just recovers the sum of O&M and capital costs (return on existing assets plus costs of new capital expenditures) for the price cap period.

Ofgas noted that applying a NPV calculation required very detailed information. In particular, "information will be required from Transco on expected capital and operating expenditure over an appropriately long period, say 25 years, based on a range of scenarios. Such expenditure will be subject to efficiency studies which will include a check on whether anticipated technological developments will extend the life of existing assets and reduce their replacement costs".[32]

While the NPV calculation was to be the primary basis for the price controls, Ofgas noted that other factors should be taken into account during the review. One important consideration was "the need to satisfy the reasonable expectations of British Gas' shareholders, including the expectations resulting from past regulatory decisions".[33]

31. Office of Gas Supply, *Price Control Review, British Gas' Transportation and Storage: A Consultation Document*, June 1995, p. 22.
32. Office of Gas Supply, op cit, p. 22.
33. Office of Gas Supply, op cit, p. 23.

One reason this was important is that “any attempt to ignore shareholders’ reasonable expectations would raise the future cost of capital and therefore reflect adversely on customers, in that future allowable revenue would need to be higher than would otherwise be the case”.[34]

Based on these considerations, Ofgas recommended that prices be cut by 20% immediately and that the X-factor be set at 2.5%. Transco objected to these proposals, claiming that no initial price reduction and an X-factor of 2.25% were warranted. It appealed Ofgas’ decision to the MMC. During the course of the appeal, Ofgas reassessed its calculations and requested an additional 9% be added to the initial rate reduction, for a total rate decrease of 29%.

The MMC ultimately decided that Transco rates should be reduced immediately by 21% and that the X-factor be set at 2%. This was much closer to the regulator’s recommendations than to the company’s, because the MMC’s valuation of BG assets was more similar to the Ofgas valuation.

Transco’s price control was most recently reviewed in 2002. This review was similar to that for UK RECs in 2000. The same basic “building block” approach we described in detail earlier was used for updating the control, but there was greater (although still not transparent) use of benchmarking and moves to strengthen the link between service quality and financial performance. Also, for the first time, separate price controls were established for Transco’s gas transmission and gas distribution services. For the gas transmission control, there will be an initial price cut of 3.1% and an X factor of 2%. For gas distribution, there will be an initial price cut of 2.9% and an X factor of 2%. Transco’s current transportation rates will be formally unbundled into National Transmission System (NTS) tariffs and local distribution zone (LDZ) tariffs during the 2002-2007 period of the control.

c. U.K. Water

In 1990 Britain’s Water and Sewerage companies were privatized and subjected to price caps. This privatization established different X-factors for different companies subject to the plan. The X-factors varied primarily because the Water Companies had differing levels of water quality, and all were compelled to raise their quality to levels

34. Office of Gas Supply, op cit, p. 23.

specified by the European Union. The different X-factors reflected the differing investment amounts that companies would have to undertake to comply with this policy directive, as well as to compensate for under-investment in the past. Due to the substantial investments that were required, the water companies at privatization were required to put forward formal ten-year investment programs, known as asset management plans. This mandate was unique among privatized British utilities.

Because the investment program costs were substantial for many companies, rates for most water companies were allowed to grow more rapidly than RPI inflation. This was equivalent to implementing negative X-factors. The PCI for the Water Companies is sometimes referred to as an "RPI+K" regime to reflect the fact that water utility prices have typically grown more rapidly than general inflation. In the initial 1990-95 price cap plan for the Water Companies, the average K factor was +5.0%.

The water company price controls were reviewed in 1994. The methods used to update the controls were similar to other British plans and were based on the now familiar "building block" estimate of forward-looking costs, including future planned capital investments. The plan retained an "RPI+K" approach, with an average K factor of 1.4%.

In this review, the regulator (Ofwat) also began to distinguish conceptually between a "normal" X-factor and a Q factor related to quality expenditures. Hence K was identified as having two components, so that K= (-X) + Q, although these components were not identified separately. However, Ofwat documents do distinguish between the revenue allowed to finance quality improvements and the reductions in revenue assumed for efficiency gains. Using these data, it can be determined that the average X factor was 1% in both the 1990-95 and 1995-2000 plans. The associated average Q factors were therefore 6% in 1990-95 and 2.4% in 1995-2000.

The water utilities' plans were also reviewed in 1999 for new controls over the 2000-2005 period. This review led to price decreases rather than increases, on average, over the plan period. The average X factor over the plan was 2.1%. This was distributed as a 12.3% price cut in 2000, and average X factors of 0.4%, -0.1%, -1.1%, and –1.5% over the remaining four years. This was the first time a price control update led to price declines, on average, for the water utilities. Ofwat said that the reason price declines were possible was that the utilities had made substantial efficiency gains over the 1995-2000 control (even while making substantial capital investments).

A basic building block approach was also used to update the controls for the 2000-2005 period, but three major innovations were added to this approach. The first was creating an "efficiency carryover mechanism." The second was establishing specific and explicit benchmarks for different cost categories. The third was allowing price controls to reflect *relative* cost and service quality performance among companies.

The "efficiency carryover" mechanism was specifically designed to maintain strong incentives near the end of the incentive plan. Absent this mechanism, firms may be disincented from cutting costs near the end of a five-year CPI-X plan since the benefits will be taken away immediately when the plan is updated. The efficiency mechanism is computed as follows:

- There are agreed "benchmarks" for O&M expenditures and capital expenditures in each of the five years of the plan.
- Benchmarks were set for the 2000-2005 plan for both operating expenditures (opex) and capital expenditures (capex); allowed rates were based on these forward-looking opex and capex benchmarks.
- In each year of the current plan, the company's actual O&M and capex are compared to the benchmarks.
- The difference in opex in each year is then phased out in increments over the next five years of the plan; the formula is calibrated so that the difference between actual opex and forecast is retained in a company's rates for five years regardless of when it was attained.
- For capex, the process is similar, except the difference between actual and benchmark capex levels in each year is multiplied by the weighted average cost of capital (WACC); in this instance, rates reflect returns that companies are allowed to retain on capex savings (*i.e.*, the amount by which capex is kept below forecast), and the companies are allowed to retain these returns for five years regardless of when they were realized.
- A similar process would apparently apply for the next plan.

Ofwat also undertook considerable econometric research on the water companies' relative efficiency and used this to set minimum and "catch up" efficiency targets. Minimum targets represented the minimum, ongoing productivity improvement rates expected for all companies. "Catch up" targets depended on a company's measured efficiency relative to an explicit performance target the companies were expected to attain by a certain time. Separate efficiency estimates were prepared for operating expenditure, capital maintenance expenditure, and capital enhancement expenditure. These estimates were also prepared separately for water service and for sewerage service.[35] The main econometric outcomes are set out below (expressed as percentage change per year):

Operating expenditure

Water Service

Minimum: 1.4%

Catch-up: 0 to 3.5%

Sewerage Service

Minimum: 1.4%

Catch-up: 0 to 2.9%, 1% average

The catch up target was based on the assumption that 60% of the assessed gap between the most efficient companies and the others would be closed over the 2000-2005 period

Capital maintenance expenditure

Water Service

Minimum: 1.4%

Catch-up: 0 to 11%, 6% average

Sewerage Service

Minimum: 1.4%

Catch-up: 0 to 12%, 8% average

The catch up target was based on the assumption that 40% of the assessed gap between the most efficient companies and the others would be closed over the 2000-2005 period

35. Some water utilities were "water only" utilities, while others were combined water and sewerage utilities. Obviously the sewerage service efficiency estimates are not relevant for water only companies, while overall efficiency targets for water and sewerage companies will depend on their relative mix of water and sewerage services.

Capital enhancement expenditure

Water Service

Minimum: 2.1%

Catch-up: 2 to 19%, 8% average

Sewerage Service

Minimum: 2.1%

Catch-up: 1 to 12%, 7% average

The catch up target was based on the assumption that 75% of the assessed gap between the most efficient companies and the others would be closed in the first year of the plan.

The third innovation in the 1999 Ofwat review was that price controls depended, in part, on a water utility's relative performance. This is already evident in the fact that there were different catch-up components of the X factors, with better performing companies having lower X factors. In addition, Ofwat rewarded several companies that had relatively good service quality performance with a 0.5% reduction in their X factor (over the value otherwise determined). This corresponds to an additional 0.5% in allowed price growth in each year of the plan. Some companies with relatively poor service quality performance were penalized with a 0.5% increase in their X factor, or 0.5% less in allowed annual price growth.

B. Revenue Caps

1. U.S.

A revenue-per-customer indexing plan has been approved for the gas delivery services of Southern California Gas (SoCalGas). The company had proposed price caps but a revenue cap was deemed more consistent with its previous regulatory commitments. As with the PacifiCorp, SCE and SDG&E plans, the plan featured an industry-specific inflation measure.

The plan approved for SoCalGas represented the first approved for a California energy utility that used industry TFP research. SoCalGas presented evidence showing that TFP for the US gas distribution industry grew at 0.5% per annum. The CPUC staff conducted its own TFP study and its estimated TFP trend for the industry was identical to the 0.5% proposed by the company. The CPUC, consequently, approved a 0.5% figure for industry TFP growth and stated in its order that this number "elicited little criticism from the parties."[36]

A comprehensive revenue cap plan began in 1998 for PacifiCorp's Oregon power distribution services. The X-factor in this plan emerged from negotiations, and no evidence was presented on industry TFP growth. Energy conservation was an especially important issue in the evolution of this plan.

2. Canada

The NEB of Canada has approved comprehensive revenue caps for two oil pipelines, Enbridge Pipelines (formerly Interprovincial Pipe Line) and TransMountain Pipe Line. Plans for both companies resulted from settlement agreements. There is no evidence that industry unit cost trends were explicitly considered.

3. Britain

The power transmission services of National Grid have been subject to revenue caps since 1993. All regulated transmission services were originally subject to revenue caps. System operation services were exempted from revenue caps at the most recent plan update.

C. Partial Indexing

1. U.S.

SDG&E's first PBR plan is an important early example of non-comprehensive revenue caps. This plan, which applied to both gas and electric services, was approved in 1994. Some claim that the term "performance based ratemaking" was first coined by SDG&E personnel during this plan's development.

The plan included index-based adjustments for revenue requirements corresponding to allowed O&M expenses and capital spending. Separate O&M indexing

36. Decision 97-07-054, *In the Matter of the Application of Southern California Gas Company to Adopt Performance Based Regulation for Base Rates*, July 16, 1997. It should be noted, however, that there was less agreement on other elements of the X factor. SCG proposed a 0.5% consumer dividend, but the CPUC approved dividends that rose from 0.6% to 1.0% throughout the plan. The CPUC also added a 1.0% increment because SCG's capital stock was projected to decline during the plan. This is a fairly unique situation, and it is the only such instance of a North American CPI-X plan including an increment for a declining rate base.

mechanisms were specified for gas and electric operations. The mechanisms included inflation factors, X-factors, and adjustments for output growth.

2. Canada

Non-comprehensive revenue caps have been more widely used in Canada than in the United States. BC Gas began operating under caps for certain categories of base rate revenue in 1994. The caps pertained to O&M expenses and small capital expenditures. BC Gas also operates under a revenue decoupling mechanism called the Revenue Stabilization Adjustment Mechanism, which applies only to revenues from residential and commercial sales.

The NEB approved a non-comprehensive revenue cap plan for gas transmission services for Westcoast Energy in 1996. Indexing limited growth in the revenue requirement components covering O&M expenses and small capital additions. The formula for growth in both revenue cap indexes was forecasted inflation in a CPI. There were no explicit X or output factors in the formula. The Alberta commission has approved non-comprehensive revenue caps for NOVA Gas Transmission. The caps apply to O&M expenses and small capital additions. We discussed the OEB's TPBR plan for Consumer's Gas in the body of the paper.

D. Benchmark Regulation Comprehensive Benchmark Plans

Several comprehensive benchmark incentive plans have been approved for U.S. energy utilities, including are plans for Mississippi Power, Niagara Mohawk Power, Northern States Power, and Otter Tail Power. All involve multiple performance indicators. The Mississippi Power plan is noteworthy as an early and influential example. The Niagara Mohawk plan uses unit cost indexes for other gas and electric utilities as benchmarks for evaluating the company's unit cost performance. This was an early formal use of statistical benchmarking in U.S. regulation.

E. Targeted Benchmark Plans

1. Targeted Cost Plans

A plan for West Kootenay Power was approved in 1996. Benchmarks were developed for many narrowly defined cost categories using different inflation measures, X-factors, and output factors. An Incentive Adjustment Mechanism reduced business risk by sharing differences between Target Cost and Actual Cost with customers.

2. Service Quality Incentives

a. U.S.

SQIs are well established in U.S. regulation. These incentive plans are sometimes included as part of a larger package of PBR programs. SQIs are also sometimes a component of merger agreements. In both cases, SQIs are often viewed as "countervailing incentive" designed to ensure that utilities maintain existing quality levels even as they operate under arrangements (PBR or mergers) that create stronger incentives to contain cost.

We reviewed many U.S. SQI plans for this paper. While the specific indicators vary widely among these approved SQI plans, there are broad similarities between the types of indicators used for energy utilities. We find it useful to group service quality indicators into seven broad categories.

Safety indicators reflect possible health and safety problems if utility products are not delivered properly. Safety indicators are much more common for gas than electric utilities. An example is the time it takes to respond to calls about gas odors.

Reliability indicators measure the continuity of the basic service. Electric utilities are expected to provide a continuous power supply at all times, so interruptions in power supply constitute a diminution in service quality. Reliability is often measured by the frequency and duration of power interruptions, as summarized in measures like the system average interruption frequency index (SAIFI) and system average interruptions duration index (SAIDI).

Non–emergency on–site services pertain to non–safety related services that require visits to customer premises, such as a visit to repair a broken meter. On–site visits to restore power supplies may fall into this category if the supply problems are customer–specific rather than network–related. For example, a non–emergency on–site indicator is the percentage of non–emergency calls that the company responds to within 24 hours.

Telephone services pertain to the service quality provided by the company's phone centre. Since most customers communicate complaints or concerns by telephone, the quality of phone contacts is an important component of overall service and is often linked to other indicators (e.g., the response time for emergency visits depends in part on how rapidly calls are answered and relayed to field personnel). For example, a telephone service indicator is the average time it takes to answer customer calls.

Metering and billing indicators reflect the quality of these services that the company provides. Quality in this area will be enhanced by timely and accurate meter–reading and bill preparation. For example, quality indicators include the percentage of prepared bills that must be adjusted because of errors.

Customer satisfaction is a category that reflects how content customers are with their utilities. Indicators include overall customer satisfaction surveys.

Finally, the "Other" category includes panoply of miscellaneous indicators that have been featured in approved service quality incentive plans. Examples include employee safety and customer outreach and education programs.

Our survey reveals some interesting points about approved SQIs in the US. First, SQI plans for electric utilities almost always feature reliability indicators. Nearly all these plans have separate indicators for the frequency and duration of interruptions. Telephone indicators and customer satisfaction indicators are also popular, although other indicators have been included in approved plans.

Second, most approved plans have between five and seven indicators. Many plan updates have simplified and reduced the number of indicators used in the second plan. In a few cases, however, (e.g., SDG&E) the updated plan actually increased the number of indicators.

Third, there are both penalty–only and penalty/reward SQI plans for U.S. energy utilities. Penalty–only plans are somewhat more common, but there are many plans where the utility can be rewarded.[37]

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37. One reason that penalty-only plans are more common is that several SQIs were implemented as part of merger agreements. In these cases, the motivation for the SQI was simply to maintain existing quality levels while the consolidated utilities attempted to find cost efficiencies. In other words, SQIs in merger agreements are almost always seen as countervailing incentives against cost–cutting that can imperil quality rather than mechanisms to induce optimal service quality *per* se, and penalty–only mechanisms are usually seen as sufficient to achieve this goal.

In addition, New York has had several penalty/reward SQIs in the past but all SQIs in the state are now penalty–only. This change usually occurred during negotiated settlements between the companies and intervenor groups that took place at the outset of industry restructuring in the state. Among other things, these agreements included stranded cost recovery for utility generation assets, which was a key objective

Fifth, in penalty–only plans, it is common for utilities to be able to "offset" good performance on some quality indicators against poor performance on other indicators. Examples include the plans that apply to investor–owned gas and electric distributors in Massachusetts and National Grid–Rhode Island.

Sixth, all approved SQIs are multi–year plans. As a general rule, SQIs do not invite reviewing or modifying indicators, benchmarks or penalty/reward rates on an annual basis. In some cases, benchmarks are updated according to formulas (e.g., rolling averages) that are specified at the plan's outset. However, in these cases, formulae rather than fixed benchmarks were applied, primarily due to the lack of data at the plan's outset. Using rules (including fixed benchmarks for the duration of the plan) rather than regulatory discretion is consistent with sound incentive mechanism design.

Seventh, there are many examples of benchmarks based explicitly on a company's historical performance. One good example is in Massachusetts, where a statewide examination of service quality issues established benchmarks for each utility based entirely on the company's past performance on a service quality indicator. For all electricity indicators, except SAIFI and SAIDI, benchmarks were based on 10 years' worth of data. Benchmarks for SAIFI and SAIDI were based on five years' worth of data.[38] In contrast to the many examples where benchmarks are based on a company's own historical experience, there are almost no examples of benchmarks based explicitly on peer performance.

Eighth, although some regulators have recognized that customer value is important for designing appropriate SQI regimes, most penalty/reward rates for performance have not been based on customer value estimates. Instead, these penalty/reward rates have been set either through negotiation between parties or through judgment. This reflects two primary factors. The first is the cost of undertaking original research on the valuation of quality to a company's own customers. The second is the fact that many SQI plans are implemented as part of a larger negotiated package (e.g.,

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for the companies. One of the things the companies traded away in the negotiating process was rewards in SQIs. Some plans (*e.g.,* the earlier New York plans, Northern States and Otter Tail Power) implement rewards and penalties via adjustments in an earnings–sharing mechanism (ESM). Better service quality raises the allowed return on equity in the ESM and reduces the probability of sharing earnings, while the opposite is true when service quality declines.

38. If a company did not have ten years of data on an indicator, new data would be used to update benchmarks until 10 years of data were available.

merger agreements, industry restructuring settlements), so service quality penalty/reward rates become another detail in a larger negotiation.[39]

Ninth, several different approaches have been taken towards applying penalties and rewards. Penalties can affect the maximum allowed price escalation rate. Penalties or rewards can be linked to each individual indicator rather than the overall index. For example; the indicator-by-indicator approach was employed in the CMP plan and, citing that precedent, it was proposed in the Office of Ratepayer Advocate's proposed alternative to the SoCalGas service quality incentive. Penalties and rewards can also be integrated into an ESM. That is, improved quality would raise the allowed ROE and reduce the likelihood that earnings would be shared, thereby benefiting the utility. The opposite would be true when service quality declines. The penalty structure in some plans is quite complex. For example, penalties can depend on how far performance is from the benchmark, and for some indicators the maximum allowed penalty that applies for a set of indicators is imposed if performance on a single indicator is sufficiently low.

Tenth, on average for the sampled companies, total penalties or rewards as a percentage of revenues are just under 2%. In some cases (e.g., Massachusetts) this limit was set by state statute rather than by the regulator. On average, about 45% of total potential penalties/rewards is tied to safety or reliability performance, about 12% to telephone centre performance, and about 43 per cent to miscellaneous other indicators (e.g., metering, billing, employee safety, customer satisfaction, etc).

b. U.K.

Public Electric Suppliers (PESs) in the U.K. have long been subject to performance standards on service quality. Traditionally there have been two types of standards. *Guaranteed standards* apply to services that must be met in every instance. If a PES ever fails to satisfy a guaranteed standard, it makes a penalty payment directly to the affected customer. *Overall standards* create minimum acceptable service levels on broader (*e.g.,* system–wide) quality measures. Companies are not subject to automatic

39. One possible exception to this phenomenon is the SQI plan for SCE. As part of the mid–term review of its PBR plan, SCE was required to present a customer service value study. The CPUC ordered this work in connection with setting appropriate reward/penalty rates for the reliability indicators in SCE's service quality incentive plan. At this time, however, this SQI plan has not yet been updated.

penalties for failing to meet these standards. However, the regulator can direct companies to take actions to improve their quality in order to comply with overall standards.

Specific standards were first introduced in 1991, and were revised in July 1993, April 1995, April 1998 and July 1998. These revisions have generally expanded the number of standards and made the performance benchmarks more demanding.

Standards also vary among companies. The initial standards varied due to differences in PES operating circumstances and historical differences in the quality levels that companies achieved. However, subsequent revisions in the performance standards have led the standards that apply to individual PESs to become more similar.

Beginning in 2002, service quality regulation in the UK was augmented to include what is known as the Information and Incentives Project (IIP). This is an effort that evolved out of Ofgem's last review of power distribution prices. In that review, Ofgem stated that it has grown increasingly concerned about the information and methods used for rate regulation. One issue was the nature of information provided by PESs. Inconsistent variable definitions, accounting practices and other factors often led to data that were not comparable across companies. This made regulation more difficult and burdensome as regulatory staff struggled to standardise data.

Ofgem also believed that its methods for price control were distorting incentives. It claimed that the regime created incentives for companies to "beat the regulator" by gaming the information provided. The IIP counters this by attempting to create incentives that are more similar to the marketplace. In competitive markets, rewards and penalties depend on a firm's performance relative to peers. The IIP incorporates this feature into regulation by placing greater weight on PES's relative performance on both cost and quality measures.

The IIP is designed to standardise information on a utility's quality "outputs" and tie financial outcomes more precisely to performance. It has four main components:

- a mechanism that penalizes companies annually, up to 1.75% of revenue, for failing to meet targets for the number and duration of supply interruptions;
- a mechanism for rewarding companies that exceed their quality of supply targets for 2004–05 based on their rate of improvement in performance up to that date;

- a commitment to rewarding "frontier" service quality performance in the next price control review; and,
- A mechanism for rewarding or penalizing companies annually, up to 0.125% of revenue, for the quality of their telephone response; beginning in 2003, rewards or penalties up to an additional 0.125% of revenue were implemented for the speed of telephone response.

The four output measures under the IIP are: (1) average number of supply interruptions per 100 customers (analogous to SAIFI); (2) average duration of supply interruptions in minutes per connected customers (analogous to SAIDI); (3) quality of telephone response, as measured by customers' expressed satisfaction on a survey; (4) and speed of telephone response, using a metric to be devised. These outputs were chosen to satisfy three criteria that they: (1) reflect what customers actually value; (2) be attributable to PES distribution businesses; and, (3) can be objectively measured over time and across companies.

The benchmarks that apply for the number and duration of interruption indicators are based on the 2004–05 benchmarks that were established when the IIP was created. These targets are company–specific and designed to be at least as demanding as each PES's actual performance on the indicators in 2001–02. For some companies, adjustments to these benchmarks that were made due to changes in data definitions and measurement systems were implemented to standardize interruption reporting. The telephone services quality benchmark is based on the average performance of other PESs, a peer benchmark. Ofgem thinks that the benchmark for the speed of telephone services will be based on an absolute number for each company rather than a peer–based benchmark. There are no deadbands around any of the benchmarks.

Penalties or rewards depend on how companies perform relative to the established benchmarks. The maximum penalty/reward is specified as a percentage of revenues, and this percentage varies over the three year term of the IIP. In the first year, maximum penalties are capped at 0.85% of distribution revenue. This is the sum of three separate caps: 0.5% related to duration of interruptions, 0.25% for number of interruptions, and 0.1% related to the quality of telephone response. In the last two years of the IIP, the overall cap is 2% of revenue. This is the sum of a 1.25% cap duration of interruptions, a 0.5% cap for number of interruptions, a 0.125% cap for the quality of telephone response, and a 0.125% cap related to the speed of telephone response. Caps are lower in the plan's first year due to uncertainties associated with the new data definitions and measurement systems. A PES would earn the maximum reward on the number of interruptions indicator by "exceeding" the benchmark by 15%. A PES would earn the maximum reward on the duration of interruptions indicator by "exceeding" the benchmark by 20%. Greater performance gains are required to gain maximum rewards on the duration indicator because Ofgem believed distributors have more ability to improve performance on duration *vis–à–vis* number of interruptions.

Ofgem also intends to reward PESs that exhibit "frontier" service quality performance when the distribution price controls are updated. This will involve comparing PESs' performance on the interruption number and duration indicators. Ofgem acknowledges that factors beyond management control can affect reliability performance and should be controlled for when making inter–utility comparisons. It is accordingly developing a "normalisation" model designed to quantify the factors' effect, to promote more robust comparisons among PESs. Among the factors being examined in this model are customer density, severe weather, and tree growth.

Service quality regulation for British Gas has generally paralleled that for the electricity industry, albeit with a lag. Service quality issues did not initially receive as much attention as in electricity. For example, unlike with the RECs, the gas regulator did not regularly monitor and report on British Gas' service quality. Over time, however, concerns with the quality of British Gas services led to greater regulatory attention. It also natural that service quality regulation for gas would closely parallel that for electricity since 1999, when the Office of Electricity Regulation and the Office of Gas Regulation were merged to form Ofgem (the Office of Gas and Electricity Markets).

Like the RECs, there have been guaranteed and overall standards for British Gas. There were initially guaranteed standards for appointments to provide gas services, getting a gas supply, and continuity of gas supply (*i.e.*, gas interruptions). Failure to achieve these standards led to an automatic payment of 20 pounds to affected customers.

In the 1992-1997 plan, the following overall standards were created:

- 97% of controlled gas escapes responded to in one hour.
- 97% of uncontrolled gas escapes responded to in one hour.

- 93% of customers contacted within 2 days of complaint and visit within 5 working days of contact.
- 90% of telephone calls answered within 30 seconds.
- 90% of correspondence responded to within 5 working days.

The Transco plan (2002-2007) maintained these indicators and benchmarks. Three additional standards were also been added to the last plan: (1) notification of planned supply interruptions; (2) informing customers of when they are due to be reconnected; and (3) substantive response to complaints within 10 working days.

The most recent Transco plan also announced plans for an IIP type project. Like the IIP for the RECs, there is to be an explicit link between Transco's allowed prices and its service quality performance. The details of this incentive mechanism have not yet been worked out.

Service quality issues have been important to British water utility regulation from the beginning. Every price control for U.K. water and sewerage companies has considered quality targets explicitly. Some of these quality goals reflected mandates from the European Community and other policymakers.

However, until recently, regulating water utilities' service quality focused more on the inputs used to deliver quality rather than quality outputs. These inputs were primarily the investments that water companies made in order to improve quality. Companies presented formal asset management plans that detailed these investments, and the costs associated with these investments drove the rapid price increases for water and sewerage services.

Quality regulation has therefore been irrevocably tied up with the broader issue associated with water utility service costs. This has, in turn, led to the delineation of separate X and Q components of the K factors. However, these X and Q factors are not really a difference in kind. Rather, they refer to different cost trends (*i.e.*, the cost of quality improvements vis-à-vis efficiency gains) and how these cost components impact overall utility costs. Both X and Q were also determined at the outset of the regime, and the latter did not depend on a company's actual service quality performance under the plan. This differs from the typical specification of SQI plans, where Q factor adjustments depend on service quality that is actually delivered under the plan.

This approach was modified somewhat in the 1999 review, when Ofwat adjusted price controls explicitly for a water utility's past service quality. Allowed price limits were adjusted up by 0.5% annually for companies that were found to provide superior quality to the industry generally, while allowed prices were adjusted down by 0.5% annually for companies providing relatively poor service quality. This assessment was based on a weighted average of company scores on many quality measures during the years 1996 through 1999.[40]

40. Details are spelled out in the Ofwat document, *Assessment of the Overall Service Provided to Customers*, 30 September 1998 (MD139). These quality evaluations were quite complex, involving nearly 70 indicators in broad areas such as water supply, sewerage service and flooding, environmental impact, water pressure, company contact (with customers), and other customer service. Quality was evaluated on both a "levels" and "rate of change" basis. The weights applied to any given indicator broadly reflected customer preferences, as determined through Ofwat-sponsored surveys.