D.P.U. 94-158

Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction.

TABLE OF CONTENTS

I. INTRODUCTION

A. Procedural History

On September 20, 1994, the Department of Public Utilities ("Department"), on its own motion, opened an investigation ("Notice of Inquiry") into the theory and implementation of incentive regulation (sometimes referred to as performance-based regulation) that could be applied to public utility companies providing electric and gas service in Massachusetts. In its Notice of Inquiry, the Department reaffirmed that its goal is to provide a framework that ensures that the utilities it regulates provide safe, reliable, and least-cost service, and stated that the fundamental question to be addressed in this proceeding is whether consumers of electricity and natural gas in Massachusetts would benefit if the current system of regulation were modified or replaced with one or more alternative regulatory approaches. Notice of Inquiry at 1-2. The Department emphasized that "the primary objective of such an alternative regulatory framework should be to provide marketplace benefits to consumers through (1) more efficient utility operations, (2) stronger utility incentives for better cost control, and (3) enhanced opportunities for lower rates." Id. at 5. In addition, the Department noted its intent to focus its investigation on whether incentive regulation could improve upon the existing regulatory framework as applied to gas and electric utility companies and whether alternative forms of regulation could better accommodate the transition from monopoly to competition that is now underway in the gas and electric industries.

The Department invited written initial comments and reply comments in response to a list of questions appended to its Notice of Inquiry opening this investigation. The Department stated that after consideration and analysis of the comments it would decide whether hearings were appropriate and conclude its investigation by issuing a policy statement on incentive regulation for the electric and gas industries.[1] The investigation was docketed as D.P.U. 94-

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1 The Department has determined that the two rounds of comments received in this case (continued...)

158.

Pursuant to a procedural schedule established by the Department in its Notice of Inquiry, written initial comments were received by the Department on November 1, 1994. Twenty-eight persons filed written initial comments: Associated Industries of Massachusetts ("AIM"); the Attorney General of the Commonwealth ("Attorney General"); Bay State Gas Company ("Bay State"); Boston Edison Company ("BECo"); Boston Gas Company ("Boston Gas"); Broad Street Oil and Gas Company ("Broad Street"); Coalition of Non-Utility Generators ("CONUG"); Colonial Gas Company ("Colonial Gas"); Commonwealth Electric Company and Commonwealth Gas Company (together, "COM/Energy"); Conservation Law Foundation ("CLF"); Division of Energy Resources ("DOER"); Eastern Edison Company ("EECo"); Energy Consortium ("EC"); the United States Environmental Protection Agency ("EPA"); Essex County Gas Company ("Essex"); Fitchburg Gas and Electric Company ("FG&E"); Massachusetts Alliance of Utility Unions ("MAUU"); Massachusetts Energy Efficiency Council ("MEEC"); Massachusetts Municipal Wholesale Electric Company ("MMWEC"); Massachusetts Electric Company ("MECo"); Natural Gas Clearinghouse ("NGC");[2] New England Cable Television Association ("NECTA"); New York Mercantile Exchange ("NYMEX"); Raytheon Company ("Raytheon"); Tellus Institute ("Tellus"); Western Massachusetts Electric Company ("WMECo"); XRE Corporation ("XRE"); and the Town of Yarmouth ("Yarmouth").[3] Written reply comments were received on

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[1](...continued)
provide a sufficient basis for the conclusions reached in this Order, and that hearings are unnecessary at this stage in the development of the issue of incentive regulation.

[2] In its Initial Comments, NGC filed a motion to intervene in this proceeding. The Notice of Inquiry in this docket invited all interested persons to file comments, but did not provide for intervention, because the proceeding in this case is not a formal adjudication and did not contemplate intervention. NGC's motion is therefore moot.

[3] The initial comments will be referred to using the commenter's name and page number being cited. For example, Attorney General at 1.

December 15, 1994 from 14 commenters: the Attorney General; Bay State; Berkshire Gas Company ("Berkshire Gas"); BECo; Boston Gas; CONUG; Colonial Gas; COM/Energy; CLF; DOER; FG&E; MAUU; MEEC; and WMECO.[4]

B. Background: Traditional Cost of Service/Rate of Return Regulation in a Changing Environment

Since the time of its establishment by the Massachusetts Legislature in 1919, the goal of the Department has been to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers. In seeking to achieve this goal, the Department has traditionally relied on cost-of-service/rate-of-return regulation ("COS/ROR") to determine utility rates. COS/ROR regulation permits utilities to charge rates that allow them to recover reasonable operating expenses and to earn a fair return on investment.

In calculating the costs incurred by a public utility to deliver its services to the public, COS/ROR regulation includes expenses such as wages and benefits for employees, depreciation on utility plant in service, and fuel,[5] that the Department finds are reasonable or have otherwise been prudently incurred by the utility. Next, the utility's level of allowable investment, or rate base, is determined. A utility is also entitled to the opportunity to earn a reasonable rate of return on rate base, which represents the return that the utility's shareholders could earn in relation to other companies that are similarly situated and face similar levels of risk.[6] This is a cost, similar to other categories of cost, because investors will

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4 The reply comments will be referred to using the commenter's name, reply and page number being cited. For example, Attorney General Reply at 1.

5 The Department notes that some expenses, most notably fuel expenses, are subject to specific statutory requirements, which establish the procedure for approval. See G.L. c. 164, § 94G.

6 The discretion of regulators under COS/ROR regulation to adjust a utility's rate of return is limited by the constitutional requirement that a regulated utility be given an opportunity to earn a fair return on amounts prudently invested. See Section III.B, (continued...)

not make capital available to utilities unless they are adequately compensated. The rate of return is added to the utility's other costs (the "cost-plus" mechanism) to produce the utility's total revenue requirement. Retail rates are then designed to generate revenue equal to the revenue requirement. A specific allocation of revenues to be collected from customers in each rate class is made, primarily according to the costs of serving each particular class in order to avoid unreasonable price discrimination and subsidization between customers and classes of customers. These determinations are made in the context of an adjudicated rate case under G.L. c. 164, § 94.

COS/ROR regulation is part of the comprehensive statutory framework under which the Department regulates the electric and gas industries in Massachusetts, and which has long been deemed essential because the public utility industries were thought to exhibit the characteristics of a natural monopoly.[7] However, despite the Department's reliance on COS/ROR regulation in recent decades, the form and method of regulation of public utilities is not fixed by statute. Statutes typically prescribe only that rates be just and reasonable, or be consistent with the public interest.

In recent proceedings, the Department has indicated its willingness to re-examine its policies and procedures, including its COS/ROR regulatory framework, and to explore whether alternative approaches could better serve the public interest. In its Order in Mergers and Acquisitions, D.P.U. 93-167-A (1994), the Department noted that commenters in that proceeding had encouraged the Department to review the existing regulatory framework and to

(...continued)
infra; see also Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1942); Bluefield Water Works and Improvements Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

[7] See, e.g., Report of the Special Commission on Control and Conduct of Public Utilities, Authorized by Resolves of 1929, Chapter 55 (House No. 1200), at 48-49 (1930).

explore alternatives, including incentive regulation.[8] The Department recognized "the potential of alternative regulatory mechanisms to improve the performance of regulated companies" and noted that "it is worth investigating whether significant benefits could accrue to customers ... ." Id. at 21. The Department's Order in D.P.U. 93-167-A announced its intent to initiate the instant proceeding, stating that it is "firmly committed to moving towards a more competitive market as a means to achieve our regulatory goals. Performance-based [i.e., incentive] regulation may well be an appropriate framework in which to achieve these goals on an interim basis before competition's potential is fully realized." Id. The Department has in fact taken steps in the direction of incentive regulation for several years, approving incentives in areas such as electric generating unit performance, gas margin sharing, demand-side management ("DSM"), and price caps. See Notice of Inquiry at 3; Section III.C, infra.

The need for adaptability in the Department's regulatory approach is underscored by the changes that are now underway in the electric and gas industries because of developments in these industries over the past two decades. These include advances in technology and in governing law, e.g., the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Clean Air Act Amendments of 1990, the Energy Policy Act of 1992 ("EPACT"), and Federal Energy Regulatory Commission ("FERC") Order 636 (1985).

During the past two decades, the gas industry has become increasingly competitive. On the national level, the industry has witnessed the deregulation of wellhead gas prices and the unbundling of the transportation and merchant functions of interstate pipelines under FERC Order 636. These changes have promoted expanded choices for local distribution companies ("LDCs") and many end-use customers. In a relatively short time, the regulatory landscape has been altered to promote choice and industry-wide competition. The Department was quick to recognize the potential benefits of enhanced choice and in 1987, during the transition to a

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8 Colonial Gas and North Attleboro Gas Company recommended that the Department explore alternative regulatory mechanisms. D.P.U. 93-167-A at 20.

more unbundled marketplace, ordered Massachusetts LDCs to develop transportation rates, which permit end-users to purchase their own supplies and have them transported through the LDCs' distribution systems. See Gas Transportation, D.P.U. 85-178, at 66 (1987). While the Department recognizes that robust, full competition for sales to many markets has not yet developed in the gas industry, the potential exists to enhance customer choice and to promote full and fair competition.

The electric industry is also undergoing change. PURPA began the process that has created an independent generation sector and a competitive wholesale market for electric power, by requiring all utilities engaged in the distribution of electricity to offer to purchase electricity produced by qualifying cogeneration and small power production facilities. EPACT then lifted Public Utility Holding Company Act restrictions on new utility electric generation, creating a class of exempt wholesale generators, and also encouraging the development of independent generating facilities by giving FERC the authority to require transmission access for such facilities. This change, analogous to FERC's policy unbundling interstate gas pipeline services, is intended to foster more efficient use of the transmission network by producers and consumers. EPACT built on the foundation established by PURPA to ensure more fully developed competition in the wholesale electric generating market.

Thus, the trend in both the electric and gas industries is toward competition. While some aspects of their operations, such as transmission and distribution, still exhibit monopoly characteristics, others, such as gas supply procurement and wholesale electricity trading, are significantly more competitive than they were just a few years ago. Further changes, such as increased competition between electric generating units and increased customer choice in both electric and gas industries, are likely. See Interruptible Transportation/Capacity Release Generic Investigation, D.P.U. 93-141; Notice of Inquiry into Electric Industry Restructuring, D.P.U. 95-30. Many of these latter changes are facilitated by the rapid development and application of advanced information technology in areas such as metering.

The Department also notes that other jurisdictions, both in the United States and abroad, have taken initiatives to make utilities more competitive.[9] The changes in other jurisdictions, some of which are contiguous to Massachusetts or which participate in pooling arrangements, such as New York and Maine, also contribute to the competitive pressures on Massachusetts. As noted in the Order opening the investigation into electric industry restructuring, D.P.U. 95-30, at 2 (Issued February 10, 1995):

> The terms on which electricity is made available are critical to the ability of industries in Massachusetts to compete nationally and internationally, thereby providing good jobs and contributing to a sound economy. They are also of concern to every Massachusetts household, as direct consumers of electricity. For businesses and residential consumers, electricity may be the most important major item in their budgets that they must purchase from a monopoly provider. The Department notes that Massachusetts electricity consumers now pay some of the highest electricity rates in the United States ... The impact of high electricity rates on residential and smaller commercial customers is also of great concern to the Department.

Similar concerns apply to the gas industry in Massachusetts. The relatively high utility rates in Massachusetts have put the state at a competitive disadvantage, both nationally and internationally, in competing for investment in the industrial sector; industrial consumers of Massachusetts gas and electric utilities have argued strongly for more competitive rates for large users. Current utility rates also burden small commercial and residential customers. Consumer demands for more choice and lower prices are therefore a major impetus for change

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9 In the electric and gas industries, as of the Department's most recent review, 29 jurisdictions had implemented DSM incentive plans; twelve jurisdictions had implemented incentives for nuclear facility performance; five jurisdictions had implemented plant-performance incentives that were not nuclear-specific; five jurisdictions had implemented fuel-cost related incentive plans; five jurisdictions had implemented broad-based incentive mechanisms, either price cap/index or rate of return/profit sharing mechanisms; and ten jurisdictions had implemented other types of incentive plans. See, e.g., "State Ratemaking Incentives," Regulatory Research Associates, Inc. (July 15, 1994). Other countries, such as Argentina, Chile, the United Kingdom and Norway have restructured their electric industries and moved toward electricity markets that are more open than any in the United states. See "Global Evolution of Competitive Power Markets," Alex Henney, Public Utilities Fortnightly at 39 (January 15, 1995).

in these industries.

In the face of the pressures for change in the utility industries, which will require adaptability on the part of utilities and regulators in order to tailor products and services to consumers' needs, and to take advantage of competitive opportunities, it seems unlikely that COS/ROR regulation, with its lack of flexibility and frequent, lengthy rate procedures, will continue to bring the benefits to consumers that it has in the past. Because of changes in regulation and in the basic energy markets themselves, the continued existence of "natural" monopoly in the electric and gas industries is in serious doubt. In addition, the defects of traditional COS/ROR regulation are well known. The "cost-plus" approach under COS/ROR regulation contributes to (1) lack of incentive for cost control, through its inherent bias favoring expenditures which can be passed through to customers; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset performance; (6) risk-averse management; and (7) disincentives for innovation. COS/ROR regulation is also a costly method of regulation, and is characterized by long lags both in reflecting and controlling actual utility operations and their costs. See July 1994 Massachusetts Electric Utility Market Reform Task Force Report, Attachment 3, at 1-3 ("Task Force Report").[10] These limitations could have particularly acute consequences for gas and electric utilities in the rapidly changing regulatory and market environment.

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[10] In December 1993, Governor William F. Weld convened a group of individuals representing a cross section of stakeholders in the electric utility industry to serve on the Massachusetts Electric Utility Market Reform Task Force ("Task Force"). In July 1994, the Task Force published the Task Force Report with findings regarding the existing regulatory system in Massachusetts and made recommendations that it believed would help lower the costs of electricity to consumers in this state. Regarding incentive regulation, the Task Force stated that it "recognizes the many potential benefits of replacing the current cost-based regulatory structure with a system that will provide for efficient utility operations and cost reductions" (Task Force Report, Chairmen's Message at 1). The Task Force also recommended that "the [Department] ... encourage utilities to submit innovative proposals for establishing incentive regulation." Task Force Report at 3.

As the Department indicated in its Order opening this investigation, this inquiry focuses on incentive regulation both as a potentially superior alternative to traditional regulation and as a means of better facilitating the transition to a more competitive environment in the electric and gas industries, with benefits for both consumers and the industries.

II. SUMMARY OF COMMENTS

A. Introduction

In its Order opening this case, the Department solicited comments on a series of 19 questions in the following categories:

- Overview-Theory and Jurisdictional Considerations;
- Broad-Based Versus Narrowly-Targeted Incentive Programs;
- The Effect of Incentive Regulation on the Current Regulation of Electric and Gas Companies' Services; and
- Procedural Considerations Concerning the Implementation of Incentive Regulation.

The comments fall into the following categories, and are summarized under these headings below:

- Department Jurisdiction;
- Standards of Review;
- Specific Mechanisms;
- Specific Cost-Recovery Issues;
- Access to Capital Markets; and
- Accounting Issues.

Generally, the commenters agree that the Department has jurisdiction to implement incentive regulation within current legal and statutory parameters, while reserving specific comment on any particular proposal, because there may be jurisdictional issues that are fact-specific to a proposal. Most commenters agree that properly designed incentives could provide a more efficient means of achieving the Department's regulatory goals. Of particular note is that many commenters argue that incentive regulation is most appropriate for those utility functions that are or will for the foreseeable future remain monopoly services, while the appropriate role for the Department regarding those functions that are potentially subject to competition is to allow full and fair competition as soon as possible. There is also general agreement that it would not be necessary or appropriate for the Department to endorse a particular incentive mechanism in this proceeding. Instead, the commenters urge the Department to set forth its broad policy on incentives, especially its specific goals for this form of ratemaking and the general types of incentive approaches that would satisfy the Department's public policy objectives. Commenters are concerned that the treatment of current regulatory policies such as DSM and low-income rates within incentive proposals be addressed, and that clear guidelines for filing utility-specific incentive proposals be provided. Importantly, several commenters emphasize that incentive regulation must consider the unique circumstances of individual utilities, and that approval of different types of incentive proposals would be appropriate and even productive in developing this form of ratemaking. On the implementation of incentive proposals, most commenters urge the Department to seek voluntary proposals by the utilities in order to encourage utility involvement and commitment to the process and avoid litigation.

There is a considerable variety of opinion among the commenters about the details of an acceptable incentive proposal, including (1) the necessary preconditions for incentive regulation; (2) the need to restructure the utility industry; (3) the role of competition; (4) the use of targeted vs. broad incentives; (5) protections for current policy objectives such as DSM and low-income rates; (6) how and indeed whether to maintain utility financial integrity in a changing marketplace; and (7) how to ensure safe, reliable, and least-cost service to customers under an incentive approach.

B. Department Jurisdiction

Although some commenters reserve comment on the issue of jurisdiction, pending an opportunity to review the details of a specific proposal, there is basic agreement on the following general points. The commenters generally agree that, under case law and pursuant to G.L. c. 164, the Department has broad authority and precedent to implement different forms of ratemaking methodology, including incentive regulation, provided the methodology (1) does not result in rates that are confiscatory to the utility, exploitative to ratepayers, or otherwise illegal; (2) is consistent with other Department statutory obligations and policies, e.g., fuel charge recovery, pole attachment fee calculation, DSM, low-income rates, recovery of costs under past Department orders; (3) is consistent with the boundaries of state and federal jurisdiction; and (4) is based on reasoned, informed judgement, including consideration of company-specific circumstances and implementation and adjustment through reasoned deliberation (See Attorney General at 1-5; Bay State at 5-8; Boston Gas at 1-3; BECo at 29-30; CONUG at 8-9; Colonial Gas Responses to Department Questions 1, 2; COM/Energy at 20-24; EECo at 10-11; Energy Consortium Responses to Department Questions 1, 2; FG&E at 4-5; MECo at 2-4; NECTA at 1-13; WMECo Response to Department Question 1).

While acknowledging the Department's broad supervisory authority over gas and electric utilities and its latitude in selecting a ratemaking methodology, consistent with the above principles, some commenters sounded a note of caution regarding potential problems. COM/Energy highlights a number of potential jurisdictional conflicts that could occur under incentive regulation. COM/Energy cites several state statutes that impose specific filing requirements, obligations, or standards on utilities or Department review, and argues that a broad-based incentive program or price-cap scheme could conflict with these, requiring statutory change to implement such incentive regulation (COM/Energy at 21-22, citing G.L. c. 164, § 94G (fuel charge statute); G.L. c. 164, §§ 69G et seq. (the siting statute); G.L. c. 164, § 94A (long-term gas and electric contracts); G.L. c. 164, §§ 30, 70-76C, 86-91 (franchise obligations); see also BECo at 30; EECo at 10-11; NECTA at 1-13 (focusing on potential conflict between a change in ratemaking methodology and the Department's obligations under the statute governing pole attachment fees for cable companies, G.L. c. 166, § 25A); WMECo Response to Department Question 1). COM/Energy also claims that implementation of broad incentives would be inconsistent with much of the Department's current regulation, including its policies on Integrated Resource Management ("IRM"), DSM, low-income subsidies, geographically-averaged rates, environmental externalities, the obligation to serve, safety and reliability requirements, and the concept of service territories (COM/Energy at 22).

While acknowledging that the potential for conflict between an incentive proposal and the current regulatory framework depends on the specifics of the proposal, COM/Energy claims that the effective implementation of a broad-based incentive scheme could require (1) substantial modification or elimination of the fuel clause statute; (2) changes in the statutes establishing service territories; (3) modification of the statutes requiring review of planning and service-obligation issues; and (4) substantial changes to policies regarding, for example, DSM and low-income rates (id. at 23).

According to COM/Energy, a broad-based incentive scheme would also risk conflict with federal law through potential infringement on pre-existing statutory or contractual obligations imposed by FERC or the requirement of market structure changes that have federal and state elements (id. at 23-24). Finally, COM/Energy claims that without prior resolution of such issues, major regulatory changes that were imposed unilaterally by the Department would be marked by litigation and resisted by utilities (id. at 23).

Conversely, Colonial Gas claims that it is not broad-based incentives, but narrowly targeted ones, that could create jurisdictional problems. For example, Colonial Gas states that if the Department were to allow a utility to use a narrowly targeted incentive to enhance the efficiency of interstate capacity use by promoting interruptible sales to on-system customers without providing comparable incentives for off-system sales or capacity releases, this would implicate federal jurisdiction under FERC Order 636 and raise issues of pre-emption (Colonial Gas Response to Department Question 2).[11]

CLF states that incentive ratemaking has the potential to substantially affect the environmental impacts of the electric power system by exempting utilities from the financial consequences of changing environmental rules and by displacing the least-cost objectives of current IRM regulations (CLF Reply at 2). CLF claims that the Massachusetts Environmental Protection Act, G.L. c. 30, § 61 ("MEPA") requires the Department to analyze any environmental impact that incentive ratemaking may have and to mitigate or eliminate any such impact to the extent feasible (id. at 4).

C. Standards of Review

The Department asked commenters to address what standard of review was appropriate to evaluate an incentive proposal. Many commenters expressed their belief that the most valuable outcome of this proceeding would be a clear statement of the Department's policy on incentive regulation and explicit guidelines on how the Department would evaluate such proposals.

Many commenters recommend that the standard of review focus on general standards such as reasonableness, public interest, and the financial integrity of the utility; that it require proposals to be consistent with current jurisdictional limits, Department goals and the Department's obligations under other statutes, or that it propose specific legislative changes where appropriate; that it be flexible enough to reflect individual circumstances of utilities and to meet the changing needs of customers; and that it evaluate proposals under a general standard for administrative decisions, on the basis of substantial evidence in a record, in order to determine whether a proposal is arbitrary, capricious, or otherwise unlawful (see Bay State

[11] Interstate capacity refers to natural gas pipeline capacity that enables the transportation of natural gas across state boundaries and is therefore subject to FERC jurisdiction under the National Gas Act and/or the Natural Gas Policy Act.

at 23-24; Boston Gas at 2, 7-8; COM/Energy at 37-38; FG&E Response to Department Question 17; MECo at 15,17; WMECo Response to Department Question 17).

The general criteria that Colonial Gas proposes are endorsed by several commenters. Colonial Gas urges the Department to require any proposal to demonstrate that any new approach is more likely than current regulation to advance the goals of economic efficiency, cost control, lower rates, less regulatory burden and continuing financial viability of the utility (Colonial Gas Response to Department Question 17; see also CONUG Response to Department Question 17; FG&E Response to Department Question 17). In addition, Colonial argues that the design of any new incentive proposal is critical to its success and that the Department should require the design of proposals to (1) be simple, incorporating clearly defined goals; (2) provide proper motivation keyed to the Department's goals; (3) be fair, by providing symmetrical rewards and penalties for ratepayers and shareholders; and (4) have "staying power" through the incorporation of a reasonable time horizon, such as five years, in order to achieve long-term gains (Colonial Gas Response to Department Question 17).

DOER offers a similar set of principles for providing and evaluating incentives, premised on the criterion of lowering rates. Its proposed principles are derived from the July 1994 Task Force Report.[12] First, incentives must be simple to administer, unambiguous to measure, likely to endure under a wide range of scenarios, and explicitly tied to performance standards. Second, the incentive structure should be consistent with existing Department incentives for DSM, fuel purchase, and plant performance. Third, the proposed incentive scheme should include measures to ensure adequate reliability, under the requirements of the Department, the regional transmission group, and the power pool. Finally, incentives should be performance-based and focused on outputs, rather than process-based or focused on inputs (DOER at 3-4).

[12] See Note 10.

Several commenters propose more particular standards, or additions to the above principles. The Attorney General states that the Department should require a performance-based proposal to provide benefits to ratepayers by reducing rates, while still maintaining reliability, quality of service, and least-cost, least-environmental-impact service (Attorney General at 31). According to the Attorney General, a utility's performance should be measured in terms of (1) price, through, for example, a comparison of its rates with a national average; (2) system reliability, through a mechanism such as an interruption index; and (3) customer satisfaction, using customer surveys (id. at 32). Under the Attorney General's approach, each of the above criteria could be weighted, with price receiving the greatest weight, and all of the factors could be used to devise an overall performance index (id.).

In addition to the general criteria of price, reliability, quality of service and customer satisfaction, COM/Energy recommends review of the magnitude of incremental margins and company-specific factors such as customer base, load profile, service territory composition, size and access to energy supply (COM/Energy at 38). Boston Gas recommends that any incentive proposal be reviewed to determine if it (1) strengthens incentives to control costs; (2) rewards productivity gains; (3) maintains or improves service quality; and (4) affords utilities an opportunity to improve their financial integrity, including accounting for factors outside the utility's control that would impose costs and affect access to capital (Boston Gas at 7, 9).

Broad Street argues that the critical measure of utility performance and the appropriate standard for review of proposals is whether they increase competition by, for example, opening systems to competition through unbundling or open access (Broad Street at 3-4). CLF asserts that any incentive proposal must be reviewed, at a minimum, for environmental compliance, with explicit incentives developed for environmental improvement in advance of regulatory requirements. CLF also insists that these incentives must be tied to quantitative rather than qualitative criteria to avoid skewing incentives in favor of revenues and rates (CLF at 8).

Finally, Tellus recommends several criteria in addition to improvement over existing regulation, and continued safe, economical and efficient operation of generation facilities. It urges the Department to also review incentive proposals for (1) efficient and economical fuel procurement and use; (2) cost-effective, efficient, successful and comprehensive DSM; (3) efficient and economical dispatch; (4) planning and procurement of future resources at the lowest long-term cost to society; (5) minimization of the environmental costs of electricity production; and (6) the ability to achieve the goals of incentive regulation under a wide range of future scenarios (Tellus at 2).

D. Specific Mechanisms

1. Introduction

The commenters expressed near universal enthusiasm for some form of incentive regulation. Of the 28 commenters, 27 either advocated specific incentive regulation mechanisms or supported incentive regulation in principle. The sole dissenter was the MAUU, which commented that incentive regulation mechanisms are (1) not supported by evidence; (2) damage safety; and (3) "will cause substantial societal harm to Massachusetts' workers and families" (MAUU at 2).

Many commenters state that it is necessary to introduce incentive regulation slowly and carefully, and that modifications to initial efforts should be accepted as experience dictates. There is also general agreement that incentive regulation should be designed on a case-by-case basis, to account for important differences between utility companies and their service territories. For the purpose of reviewing the comments, the Department divides the mechanisms into two categories: (1) narrowly-targeted mechanisms, which focus on specific aspects of utility operation and (2) broad-based mechanisms, which address overall utility operation.

2. Narrowly-Targeted Incentive Regulation Mechanisms

Narrowly-targeted incentives are those that may be designed to stimulate performance in specific aspects of utility operation. Generally these incentives operate by tying allowed revenue bonuses or penalties (usually stated in terms of rate of return basis points) to performance in the targeted area. Commenters address the pros and cons of a number of incentive regulation mechanisms. Commenters cite several examples of targeted areas of utility operation that may be appropriate targets for narrowly-targeted incentive regulation mechanisms, including DSM, new generating unit construction costs, off-system power sales, fuel and purchased power expenses, operation and maintenance expenses, service reliability, and customer satisfaction (Task Force Report, Attachment 3, at 4).

Six commenters endorse narrowly-targeted incentive regulation mechanisms over broad-based mechanisms, stating that narrowly-targeted mechanisms would require a less drastic adjustment to the rate-making process (i.e., would not supplant existing mechanisms), would involve relatively easily measurable criteria, and would produce more predictable results (COM/Energy Reply at 9, 18; CONUG Response to Department Question 6; CLF Response to Department Question 8; EECo Response to Department Question 8; FG&E Reply at 1-2; NYMEX at 2). COM/Energy states that properly targeted incentive plans can "avoid the difficult legal, policy, and practical problems presented by a more broad-based approach, while accomplishing the Department's overall objectives" (COM/Energy Response to Department Question 5).

Three commenters oppose narrowly-targeted incentives, contending that they could lead to uneconomic behavior by giving utilities incentives to focus on targeted activities at the expense of other activities not subject to incentives (Colonial Gas Response to Department Question 8; NGC at 10; WMECo Response to Department Question 5). On the other hand, several commenters suggest the use of targeted incentives to continue support for specific policies such as DSM (Attorney General at 22; CLF at 6).

3. Broad-Based Mechanisms

Broad-based incentive mechanisms use widely encompassing frameworks, such as a company's rates or revenues. Comments were submitted on four types of broad-based incentive regulation mechanisms: price caps, revenue caps, rate of return bandwidth, and price yardsticks.

Ten commenters support broad-based incentives in general on the grounds that they mimic the market and are relatively easy to administer (AIM at 1; Attorney General Response to Department Question 5; Bay State Response to Department Question 5; BECo at 26-27; DOER at 13; Energy Consortium at 11-13; MECo Response to Department Question 5; MEEC Response to Department Question 11; WMECo Response to Department Question 11).

The four commenters that oppose broad-based mechanisms are concerned that they would result in "tangled objectives," would fail to provide a direct focus on controllable factors, and would not be adaptable to different utilities and their different circumstances (COM/Energy at 12-17; CONUG Response to Department Question 6; FG&E at 1-2; MAUU at 1.)

Some commenters suggest a combination of broad- and narrow-based incentives. For example, MECo argues that, to ensure that broadly defined incentives produce more efficiency rather than much poorer quality service, narrowly targeted incentives aimed at reliability and customer service and satisfaction should be combined with elements of a broad-based program (MECo Response to Department Question 5). Further, certain public policy initiatives, such as DSM, might also be subject to a narrowly targeted mechanism within the context of a broad-based system (id.).

Below are summaries of comments made about the four main types of broad-based incentive regulation mechanisms: price caps, revenue caps, rate-of-return bandwidth, and yardstick regulation.

a. Price Caps

Price cap regulation is simple in concept. First, an initial price cap or set of price caps is established. Thereafter, the price cap adjusts automatically as a function of inflation rates less an allowance for productivity improvement and also incorporates a factor that permits a direct pass-through of specified and pre-determined costs thought to be especially volatile or beyond the utility management's control (Task Force Report, Attachment 3, at 7-8).

Eight commenters favor price caps, saying they provide market-like incentives for efficient operations since profits would be linked to the company's ability to manage its costs within revenues limited by fixed prices (Bay State Response to Department Question 8; BECo at 26; Colonial Gas Response to Department Question 8; EECo Response to Department Question 8; Energy Consortium at 12-13; MECo Response to Department Question 5; NGC at 7; WMECo Response to Department Question 5).

Three commenters oppose price caps on the grounds that they would be harmful to DSM programs, since they tie utility revenues directly to sales and give a "perverse" incentive to sell more gas or electricity (CLF Response to Department Question 8; MEEC at 2-3; Tellus at 4). The Attorney General also criticizes the standard methods for adjusting price caps, claiming there is no demonstrated tie between utility costs and general inflation indices (Attorney General Response to Department Question 5).

b. Revenue Caps

Revenue caps set a limit on the overall revenues a company can earn, rather than capping prices. Four commenters who reject price caps call for revenue caps instead, claiming that revenue caps offer the best promise of preserving current DSM programs because they maintain the "decoupling" of utility profits from sales (CLF Response to Department Question 8; EECo Response to Department Question 8; MEEC at 3; Tellus at 5-6).

c. Rate of Return Bandwidth

Under a rate of return bandwidth approach, rates are established initially in the usual way. The allowed rate of return and a bandwidth around that figure (e.g., +/- 200 basis points) also are established. Thereafter, no rate adjustments are made as long as the earned rates of return fall within the allowed range. Returns falling outside the allowed range may trigger (1) an automatic rate adjustment to bring the earned return back within the allowed return range; (2) a deferred revenue credit or liability to be considered for inclusion in rates in a future proceeding; or (3) a review of the underlying basic rates (Task Force Report, Attachment 3, at 6).

Seven commenters advocate rate-of-return bandwidth mechanisms, claiming that they can provide a more equitable sharing of benefits between customers and shareholders than price caps would, since theoretically, companies can earn unlimited profits under price caps (Attorney General Response to Department Question 6; Bay State Response to Department Question 8; BECo at 20; Boston Gas Response to Department Question 8; Colonial Gas Response to Department Question 8; DOER at 14; WMECo Response to Department Question 8). COM/Energy opposes ROR bandwidth mechanisms on the grounds that they would "require frequent and litigious reviews" of utility costs and revenues and thus undermine the effort to reduce the regulatory burden (COM/Energy at 9).

d. Yardstick Regulation

Yardstick regulation rewards or penalizes utilities to the extent that their costs, in total or for specific areas of cost, are less than or exceed the costs for a reference group of utilities (Task Force Report, Attachment 3, at 7). The set from which those other companies are drawn might be the state, the region, or the nation.

At least three commenters endorse yardstick regulation. According to Colonial Gas, "if the benchmarks are properly established, companies would have incentives to achieve the efficiencies necessary to meet or exceed the benchmark measures" (Colonial Gas Response to Department Question 8). The Attorney General advocates the use of a yardstick mechanism that compares each company's overall price per unit of sale to national average electric and gas prices, which would reward each company based on how well it reduces the average price for all customers (Attorney General Response to Department Question 8). DOER suggests the use of cost and performance of other energy companies as yardsticks for determining revenue (DOER Reply at 4).

E. Specific Cost-Recovery Issues

The Department received comments that addressed specific cost-recovery issues in three general cost categories: (1) costs associated with public policy initiatives (e.g., environmental compliance, DSM, and low-income discounts); (2) costs associated with factors that are outside the control of the utility ("exogenous costs"); and (3) stranded investments.

1. Public Policy Costs

Commenters who focus on DSM encourage the Department to continue DSM policy programs/incentives in either of two ways. Some suggest creating a cost recovery and incentive track for DSM and "clean" energy projects, separate from any broad-based incentive program (CLF Response to Department Question 8; MECo Response to Department Question 5). According to WMECo, one way to recover these costs is through the use of a "universal service charge," which would recover costs from all electric consumers (WMECo Response to Department Question 3). Alternatively, commenters suggest integrating DSM and clean-energy policy initiatives into any new form of regulation. Possible mechanisms suggested by commenters include (1) a DSM projection within an overall price cap level in a broad-based incentive program (CLF Response to Department Question 12; MECo Response to Department Question 6); (2) a comparison index designed to account for DSM, through sales-adjustment of any per-unit price index comparison (Attorney General Response to Department Question 8); or (3) use of average bills or revenues per customer rather than price as the basis for the pricing mechanism (MEEC at 3; CLF Response to Department Question 8).

Two commenters suggest that market-driven incentive programs might be incompatible with DSM and other public policies. COM/Energy contends that the obligation to serve required by the Department and imposed by statute (e.g., G.L. c. 164, §§ 69G-69R, 92), and implemented by integrated resource planning processes, is fundamentally at odds with a market-driven, incentive framework (COM/Energy at 15). According to COM/Energy, the Department's policies in the areas of DSM initiatives, low-income rates, environmental externalities, geographically-averaged rates, safety and reliability standards, and, for electric companies, the obligation to serve all customers and the Department's IRM regulations, are clearly inconsistent with a price-driven, broad-based incentive program in the electric and gas industries (id.). Bay State recommends the Department identify any costs associated with regulatory objectives that may create tensions or contradictions in competitive marketplace (i.e., low-income subsidies) (Bay State at 4).

2. Exogenous costs

Four utilities discuss exogenous cost factors. Bay State urges the use of these to account for factors outside a utility's control, and any unique utility circumstances (Bay State Response to Department Question 7). Colonial Gas argues for excluding gas costs from price caps because of related exogenous costs (Colonial Gas Response to Department Question 13). COM/Energy warns that denial of recovery of costs outside a utility's control could be confiscatory (COM/Energy Response to Department Question 13).

CLF argues that some costs, such as environmental compliance costs, can be anticipated and better managed if explicitly included in an incentive formula. CLF also asserts that, if utilities are to be motivated to invest in "clean" technologies, environmental compliance costs should be included as a component of the incentive formula and not treated as an exogenous cost factor (CLF at 5-6). The Attorney General argues that in a competitive marketplace, exogenous costs are part of the risks of doing business and should not be treated differently by the Department (Attorney General Response to Department Question 13).

NGC notes that there are financial risk management tools that can address certain fuel cost price changes, though perceived risks associated with such tools creates a need to provide incentives and risk sharing to utilities that incur these risks. NGC argues that a utility should be allowed to hedge risks and to share the risks and rewards through an incentive rate mechanism; the utility and its customers would share equally in the costs and savings associated with hedging (NGC at 2-4). NGC contends that purchased fuel adjustment mechanisms are inherently ill-suited for hedging programs because the ex post facto review does not give the utility a set of explicit standards. According to NGC, purchased fuel adjustment mechanisms should not be used to recover costs associated with fuel price hedging (NGC at 5).

3. Stranded Investments

Stranded costs are, very generally, those costs associated with investments made under the traditional regulatory framework that may not be recoverable under a competitive pricing regime. Four of the electric utilities comment that, in order for an alternative ratemaking scheme to promote fair competition in emerging competitive markets, the scheme must allow for the recovery of costs associated with commitments made under regulation (i.e., utility costs that regulators indicated would be recoverable through rates) (BECo at 12; COM/Energy at 14; MECo at 5-6; WMECo Response to Department Question 3.)

MECo asserts that a performance-based system of regulation should ensure that a utility's commitment costs are recovered in order to avoid cross-subsidies by captive customer groups and pricing distortions in areas of operation where a competitive market is emerging (MECo Response to Department Question 3). MECo further argues that the efficient and effective movement toward competition requires that the competition proceed on a marginal cost basis (id.).

Only the Attorney General opposes explicit provision for recovery of stranded investments, arguing that, because these costs reflect past actions of inefficient utility management, the Department should not proceed on the assumption that a stranded investment recovery mechanism is required. The Attorney General asserts that captive customers should not be required to make utilities whole for specific investment decisions later found to be inconsistent with market conditions (Attorney General Response to Department Question 3).

The Attorney General adds that fairness may require that a performance-based regulation scheme recognize the costs incurred by electric utilities for any non-utility generator power that utilities were compelled to purchase at prices and under terms that they objected to (id.). In addition, the Attorney General argues, any form of performance-based incentive regulation must ensure that there are adequate funds collected from consumers to fund both current nuclear decommissioning costs and any potential increases in the cost of decommissioning (id.).

F. Access to Capital Markets

Many commentors state that the effect of incentive regulation on a utility's ability to access the capital markets would depend upon the specifics of any performance-based incentive applied. They contend that, if capital markets perceive that the risks being assigned to utilities under an incentive mechanism are disproportionate to the potential rewards, the ability of utilities to raise capital would be adversely affected (Bay State Response to Department Question 14; COM/Energy Response to Department Question 14). The commentors are virtually unanimous in stating that a well-reasoned plan with clear objectives, consistently applied incentives, and an equitably apportioned sharing of potential risks and benefits between customers and shareholders would be viewed positively by the investment community (Attorney General Response to Department Question 14; Bay State Response to Department Question 14; Colonial Response to Department Question 14; MECo Response to Department Question 14; WMECo Response to Department Question 14). Several commentors state that, while the implementation of incentive ratemaking may create short-term perceptions of increased risk in the eyes of the investment community, they are also of the opinion that a well-designed incentive plan would reduce their financial risks in the long-term (Colonial Response to Department Question 14; CONUG Response to Department Question 14). WMECo opines that a successful performance-based regulatory framework would likely shift the attention of financial analysts towards evaluating the quality of utility management instead of focusing on the regulatory environment (WMECo Response to Department Question 14).

BECo states that its proposed performance-based incentive mechanism (see Section II.D, below), if adopted by other utilities, would enable it to maintain financial integrity (BECo Response to Department Question 14). However, BECo also states that the success of other utilities with such an incentive proposal would depend upon whether their specific proposals incorporate adequate provisions for the recovery of past, prudently incurred investment costs (id.). According to BECo, any incentive plan that fails to take into account stranded cost issues could jeopardize a utility's ability to access the capital markets (id.).

Boston Gas argues that the manner by which incentive mechanisms recognize costs associated with factors outside of the control of the management (e.g., plant replacement, property taxes, interest rates, and changes in tax laws) is integral to the perceived risk of incentive-based regulation schemes (Boston Gas Response to Department Question 14).

G. Accounting Issues

1. Introduction

Investor-owned utilities maintain their accounting records in accordance with generally accepted accounting principles ("GAAP") and the requirements contained in the Statement of Financial Accounting Standards Board No. 71, "Accounting for the Effects of Certain Types of Regulation" ("FAS 71"). According to FAS 71, if a regulator directs a utility to defer an expense, a deferred asset is created on the balance sheet, and thus qualifies for consideration as a "regulatory asset."

To determine whether a regulatory asset entered on the books of a utility should properly be recognized, FAS 71 requires that there be a "reasonable assurance" that regulators will allow those specific costs to be eventually included in allowable costs for ratemaking purposes (Original Pronouncements, Accounting Standards as of June 1, 1992, Vol. 1, FAS 71). If these conditions are not met, the utility is required under GAAP to write off the deferred asset (id.). The intent of this requirement is to provide a clear link between the costs incurred by the utility and its recovery of those costs through rates.

Under broad-based incentive regulation, the link between a utility's costs and its rates may not be as clear as under COS/ROR regulation. If sufficient doubt exists that a utility's rates are linked to its costs, the utility would be required under GAAP to discontinue the application of FAS 71. Original Pronouncements, Accounting Standards as of June 1, 1992, Vol. 1, Statement of Financial Accounting Standards Board No. 101, "Accounting for the Discontinuation of Application of FAS Statement No. 71") ("FAS 101"). The utility may thus be required to write off any regulatory assets created under traditional cost-based ratemaking at the time of a conversion to an incentive plan (id.).

2. Summary of Comments

A number of commenters contend that the adoption of incentive regulation could affect the ability of the utility to recover regulatory assets under the GAAP principles laid out in FAS 71 (Attorney General Response to Department Question 15; Boston Gas Response to Department Question 15; WMECo Response to Department Question 15). They reason that if the particular incentive mechanism fails to provide assurance for the recovery of all reasonable and prudent costs, utilities could be forced to incur substantial financial losses (id.). According to COM/Energy, adoption of broad-based incentive regulation could weaken or eliminate the link between specific cost-recovery and rates, and thus require a utility to cease recognizing regulatory assets, consistent with the standards of FAS 101 (COM/Energy Response to Department Question 15).

Conversely, a number of commentors state that well-considered incentive proposals would not necessarily conflict with GAAP (Bay State Response to Department Question 15; BECo Response to Department Question 15; EECo Response to Department Question 15; MECo Response to Department Question 15). FG&E asserts that targeted incentive proposals that lay out clear cost identification, distinct and clear cost recovery rules, and appropriate timeframes for recovery would not conflict with GAAP (FG&E Response to Department Question 15). Additionally, Colonial contends that if the objectives and measures of an incentive program are clearly laid out from the start in accordance with the standards set forth by the accounting industry's Emerging Issues Task Force ("EITF"), the incentive mechanism would interact favorably with GAAP; Colonial notes the efforts of the EITF to clarify FAS standards with respect to incentive regulation (Colonial Response to Department Question 15, citing EITF Issue No. 92-7).

H. Specific Incentive Proposals

The following is a brief summary of specific incentive proposals offered by commenters.

1. Boston Edison Company

Boston Edison proposes an approach to incentive regulation that is centered on the wholesale power market. BECo's proposal contains six key features (BECo at 17). First, utility rates would be separated into a generation component covering all aspects of power supply costs, and a transmission and distribution ("T&D") component, which would cover all non-power supply costs (id.). Second, a utility's generation costs would be recovered through a wholesale market price for energy, both for existing and prospective generation sources.[13] According to BECo, it is important that the market price be universally established and accepted by all who participate in the market, with its value objectively determined and readily available to all buyers and sellers. BECo notes that the determination of the wholesale market price poses a substantial challenge at this stage of the industry's evolution because, at present, there is no single source from which such a wholesale market price can be determined (id.

[13] Thus, according to BECo, a customer would pay a two-part rate: a cost-based, T&D charge defined in the tariff, and a market-based energy charge that would vary by hour and equal the wholesale market price of energy for that hour. BECo states that under this approach, the fuel adjustment clause would no longer be used (BECo at 17-18).

at 17-18).[14] Third, T&D rates would continue to be based on cost, but would be subject to broad-based performance incentives such as price caps, or return on equity caps, coupled with provisions to ensure that service quality is maintained (id. at 20). Fourth, since generation rates would be based on market prices, generation assets would be marked down to market value. BECo contends that to provide assurances of continued recovery of above-market sunk costs, the marked-down generation assets should be accompanied by a write-up of T&D assets based on replacement cost (id. at 20-21). Fifth, environmental values would be incorporated into wholesale market prices. BECo suggests that a system of "unit specific dispatch adders be piloted with SO2 or NOX emissions" (id. at 21). Finally, at least initially, rates would continue at current levels because the write-up of T&D and write down of generation would be "intentionally designed" so that they offset each other and do not create a change in overall rate level (id. at 21-22). BECo further states that under its proposal, utility franchises would continue in place, and retail customers would not be able to choose among alternative generation suppliers (id. at 22).

Although BECo acknowledges that there are numerous issues that would need to be identified and addressed in any movement to a market-based generation system, it urges the Department to pursue the development of such a structure because it promises substantial benefits (id.). First, the proposal is structured to achieve real efficiency benefits while maintaining the financial integrity of utilities. Second, it is intended to facilitate a transition in the generation sector by assuring that no new stranded costs are possible once the plan is implemented. Third, BECo suggests that the proposal can be made equitable to all customers while still honoring the "regulatory compact" by making possible the recovery of historical,

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[14] BECo notes that, as a starting point, NEPOOL's system lambda (i.e., the cost of fuel, operations and maintenance, or unserved energy to serve the last MW of demand in a given hour) can be used as a reasonable proxy for a wholesale market price in New England. BECo recommends that the NEPOOL lambda be adjusted to compensate for a current downward bias because it fails to incorporate certain items such as marginal unit start up costs (BECo at 19-20, 27).

prudently incurred costs. Fourth, BECo claims that the proposal would simplify the current regulatory process and require less frequent rate cases. Lastly, BECo maintains that the changes required to implement the proposal would not be as disruptive as those associated with other market-based proposals such as retail wheeling (id. at 22-23).

BECo notes that full implementation of its proposal would require a substantial amount of time and effort. During the interim, BECo proposes that broad price cap regulation of non-fuel rates be implemented and that the acquisition of new resources by utilities be subject to market decision rules on an expedited basis, while the more complete application of such principles is being developed. In addition, BECo recommends that the current IRM process be set aside, and that cost recovery for new resources be limited to the wholesale market price (id. at 26-27).

2. DOER

DOER advances a specific incentive regulation model which combines the use of competition, price formulas, rate-of-return bandwidths and targeted incentives, and incorporates the present IRM structure to determine utility resource portfolios and production-related costs for captive customers until a market-based system is phased in (DOER Reply at 2).[15] DOER's model consists of two key components. First, a utility's customers would be divided into core and non-core customers.[16] Second, a utility's rates would be based on a pricing formula that unbundles rates into those associated with the generation supply function, and those associated with all other functions (id. at 12).

Under DOER's model, service to both core and non-core utility customers is based on a

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15 DOER's model regards a utility's T&D functions as natural monopolies and therefore subject to regulation, while it treats the generation function as competitive and subject to market forces (DOER Reply at 13-20).

16 DOER defines a core customer as a customer who does not have the option to obtain its own energy supplies either due to legal or regulatory rules, or limited availability of options in the market. According to DOER, a non-core customer has this option, which it may or may not elect (DOER Reply at 13).

pricing formula that is comprised of various components that are designed to reflect the costs of generation, transmission, and distribution, as well as costs associated with a utility's implementation of low-income rates and DSM programs (id. at 14). In particular, under DOER's proposed pricing scheme, a utility's core customers would pay a market-based price for generation-related costs, and a cost-based price for T&D (non-competitive utility functions) costs, along with various other adders reflecting low-income and DSM costs. Non-core customers would pay the utility the same cost-based price for T&D costs, as well as low-income and DSM adders. However, under DOER's pricing formula, the price that non-core customers would pay the utility for generation costs would be zero, because they would be free to secure their own supply, and thus would pay their own non-utility supplier a supply price for such costs (id. at 20).

Regarding the pricing of generation costs, DOER states that under its model, core customers would pay a market-based price for such costs. According to DOER, such a market-based price would be determined on the basis of an estimate of the market price of energy and capacity.[17] DOER notes that presently, because of high embedded costs, going to a market-based system immediately might cause financial harm to a utility company. As an interim measure, DOER suggests that the Department set incentive-based rates for the supply-related functions of regulated utilities designed to reflect a gradual phase-out of cost-of-service based production assets and expenses from rates (id. at 18-19).

With respect to the pricing of T&D costs, DOER states that under its proposed model, such costs would be recovered from both core and none-core customers through a retail price index ("RPI"). According to DOER, in the test year, the RPI would be set according to each utility's adjusted cost of service, and would be adjusted in following years by an inflation index

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17 DOER recommends using an estimate of marginal energy and capacity costs based on IRM, or a market index such as NEPOOL's system lambda, to establish a market price for each type of resource in the utility service mix until market price information develops (DOER Reply at 19-20).

specific to each function and by a productivity factor. DOER notes that the RPI could also be indexed to a comparison group of utilities (id. at 16).

To prevent utilities from minimizing costs at the expense of customer service quality, DOER recommends that the price formula for T&D be indexed to a measure of customer service quality (id. at 17). DOER further proposes that the price formula include a factor for DSM costs and bonuses, which could also include the incremental costs of renewables acquired to further environmental and sustainability goals, and a low-income support factor to reflect the allocation of the low-income subsidy to specific customer classes (id. at 17-18).

Finally, under DOER's proposal, a rate-of-return bandwidth would be established to monitor exorbitant or confiscatory returns on capital invested in non-competitive functions (id. at 16). DOER states that utilities would be required to file a rate case if their returns fall outside the bandwidth, or else to establish a profit-loss sharing mechanism, up to a rate review threshold, to avoid rate reviews (id. at 16-17).

3. Energy Consortium

The Energy Consortium envisions a restructuring of the electric utility industry into three independently functioning components: (1) generation, which is comprised of competing existing utilities and independent producers all of which own generating plants; (2) distribution, or "wires," consisting of companies delivering power over the local distribution lines in franchised territories; and (3) the transmission "grid," which would provide bulk transmission and operate an open power pool (Energy Consortium at 14).[18] The Energy Consortium states that the goal of this new structure is to create efficient market signals regarding the construction and operation of generating capacity (id.).

Under the Energy Consortium's model, the "grid," or the pool, would be independent

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18 The Energy Consortium states that the electric utility industry in Great Britain has been operating under this new structure since 1990, and that the electric industry in the Province of Alberta, Canada, has just recently agreed to restructure under a similar approach (Energy Consortium at 18-19).

of the generators, and would only work to provide physical reliability and economic dispatch, matching supply and demand, and would not seek to profit from sales of energy (id. at 14, 16). The Energy Consortium states that under such an approach, generators would be free to quote any price for energy offered to the pool, while at each hour the pool dispatcher would choose the cheapest supplies necessary to meet total demand on the grid. According to the Energy Consortium, this process would produce an hourly real time or "spot market" price -- the cost of energy from the marginal generator (id. at 14).

The Energy Consortium suggests that under its proposed model, every customer would have the choice of paying for part or all of its power supply on a contract price basis and/or paying pool prices ("real time spot market" prices) for non-contract power, while every generator would have the same choice for selling power. Customers without contracts (for part or all of their load) may buy power, because the pool dispatch process would ensure continuous availability, but such customers must pay the hourly-varying pool prices for that energy.[19] Likewise, generators without contracts would be able to sell energy, as long as they are willing to accept the pool price (id.).[20]

Under the Energy Consortium's model, transmission and distribution will continue to be regulated as monopoly services. The Energy Consortium asserts that each segment of the industry should be treated separately, in order to more readily identify areas where the greatest inefficiency problems exist. The Energy Consortium suggests that separate incentive regulation proposals be used for transmission and distribution costs, as well as for existing generation. In this way, incentives can be used to induce more efficient decisions about

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19 According to the Energy Consortium's proposal, customers would also pay T&D charges for the monopoly services that would remain regulated (Energy Consortium at 15).

20 Under the Energy Consortium's model, customers and generators who want to avoid the variability of pool prices can sign power supply contracts (Energy Consortium at 15).

construction and operation of transmission and distribution facilities (id. at 4).

The Energy Consortium maintains that its proposed changes provide an opportunity for both utilities and their customers to do better than under the current system because customers would have more flexibility and cost control while generators would have more opportunities to market the power they produce. In this way, both sides will benefit from streamlined regulation and the ability to apportion risk directly between them, rather than face the uncertainties of regulation (id. at 4-5).

The Energy Consortium states that it is important that the new structure be put in place as soon as practically possible in order to encourage cost cutting in each component of the industry, as well as to begin allowing customers a choice of generation supplier (id. at 4).

III. STATEMENT OF DEPARTMENT POLICY REGARDING INCENTIVE REGULATION

A. Introduction

The Department's investigation into incentive regulation for electric and gas utilities is the result of a continuing evolution in the Department's regulatory practices. The Department seeks to implement regulatory techniques that complement the changes now underway in both the electric and gas industries. Given other changes in these industries that may occur in the near future, the Department also seeks regulatory frameworks that can adjust to these changes. See Notice of Inquiry into Electric Industry Restructuring, D.P.U. 95-30 (Issued February 10, 1995). While the trend in both industries is toward competition, regulation of monopoly functions is still necessary. Furthermore, incentive regulation holds promise for improvement in the current regulatory framework, regardless of the competitive state of the industries. Incentive regulation, though potentially more compatible with increasing competition than traditional COS/ROR regulation, is distinct from deregulation because it seeks to harness direct financial incentives as well as competitive market forces in pursuit of regulatory goals.

Consistent with its Order opening this investigation, the Department emphasizes that the primary objective of incentive regulation should be to provide marketplace benefits to consumers by promoting more efficient utility operations, cost control, and opportunities for reduced electric and gas rates. In addition to delivering marketplace benefits to consumers, incentive regulation should also provide an opportunity for each electric and gas company to adjust to competition as it develops. Incentive regulation should accomplish this while still achieving the Department's longstanding goal of safe, reliable, and least-cost service. Finally, the Department is also hopeful that once start-up efforts are past, incentive regulation schemes will offer a more streamlined and efficient, flexible, and responsive regulatory process than traditional COS/ROR for utilities, intervenors, and the Department. Based on its review of the comments in this docket and the considerations outlined in this Order, the Department finds that incentive regulation has the potential to bring real efficiency gains and reduced rates to consumers.

This section addresses the issues of the Department's authority to implement incentive regulation, surveys our precedent for incentive regulation, and sets forth the standard of review, criteria, and procedure for filing incentive proposals.

B. Department Jurisdiction to Implement Incentive Regulation

In its Notice of Inquiry, the Department requested comments regarding its authority to "facilitate the development and implementation of incentive-based programs." Notice of Inquiry at 8. As indicated in Section II.B, supra, the majority of commenters stated that the Department has broad authority to implement such programs. The Department recognizes that its authority to approve an incentive proposal rests on its jurisdiction to adopt incentive regulation generally under G.L. c. 164. Therefore, the Department finds it appropriate to address whether G.L. c. 164 permits the Department to adopt alternatives to traditional

COS/ROR regulation.

The Department's jurisdiction for regulation of electric and gas service within the Commonwealth derives from G.L. c. 164. The Department has broad general supervisory power over the provision of electric and gas services. G.L. c. 164, § 76. In addition, §§ 93 and 94 of G.L. c. 164 give the Department authority over the rates of electric and gas companies. Section 94 states in pertinent part:

> Whenever the [D]epartment receives notice of any changes proposed to be made in any schedule filed under this chapter which represent a general increase in rates, prices, and charges for gas or electric service, it shall notify the attorney general of the same forthwith, and shall thereafter hold a public hearing and make an investigation as to the propriety of such proposed changes... . The [D]epartment, either upon complaint or upon its own motion, may investigate the propriety of any proposed rate, price, or charge and may, pending such investigation and decision thereon, by order served upon the company affected thereby, suspend the taking effect thereof, from time to time, but not for a period longer than six months beyond the time when such rate, price, or charge would otherwise become effective.

Thus, under G.L. c. 164, § 94, the Department is responsible for ensuring the "propriety" of proposed rates. In practice, the Department has interpreted this to mean rates that are "just and reasonable." Section 94 also requires that rates are not unjustly discriminatory or unduly preferential. See Attorney Gen. v. Department of Pub. Utils., 390 Mass. 208, 234 (1983), citing American Hoechest Corp. v. Department of Pub. Utils., 379 Mass. 408, 411 (1980).

The statute does not prescribe a particular method by which the Department must fulfill its statutory mandate of setting just and reasonable rates; nothing in G.L. c. 164 indicates that the legislature intended to limit the Department to a specific regulatory scheme, such as COS/ROR. The Department's practice over many decades in the regulation of the electric and gas industries shows a consistent pattern in construing its authority to adopt alternative methods of regulation in response to changing market circumstances and consumer needs so as to meet its regulatory objectives. While the Department traditionally has employed COS/ROR to determine just and reasonable rates for utilities under its jurisdiction, it has on numerous occasions utilized alternative or "incentive" methodologies in place of traditional rate regulation where it determined that a different methodology would better satisfy its public policy goals and statutory obligations. See Section III.C., infra. Most recently, in the telecommunications context, the Department has found that existing statutes and regulations do not prescribe a specific method or theory that the Department must follow in order to meet its statutory obligation to achieve just and reasonable rates. See NYNEX, D.P.U. 94-50 Ruling on Motion to Dismiss at 61 (February 3, 1995).

While the Massachusetts Supreme Judicial Court ("SJC") has never addressed the precise question of whether the Department can substitute incentive regulation for traditional COS/ROR, the SJC has repeatedly held that the Department has "wide discretion in choosing its approach to rate regulation" by selecting among different theories or methods. The SJC has found that the Department has broad authority to regulate rates in the electric and gas industries under G.L. c. 164, § 94. See American Hoechest Corp., 379 Mass. at 413 ("[W]hen alternative methods are available, the [D]epartment is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal.").[21]

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[21] See also Attorney Gen. v. Department of Pub. Utils., 392 Mass. 262, 268-269 (1984) ("Where the result of employing a specific [cost of capital] methodology in rate setting is not impermissible, the choice of the methodology is a matter committed to agency discretion and is beyond the scope of our review."); Attorney Gen. v. Department of Pub. Utils., 390 Mass. 208, 233 (1983) ("A choice between alternative methods of allocation of revenue needs made by [a utility] and approved by the Department is appropriate as long as it does not have a confiscatory effect and is not otherwise illegal … . Cost of service need not be the sole criterion used in establishing rate classifications."); Massachusetts Elec. Co. v. Department of Pub. Utils., 376 Mass. 294, 302 (1978) ("When alternative methods [for determining a utility's cost of equity] are available, the Department is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal."); Boston Edison Co. v. Department of Pub. Utils., 375 Mass. 1, 19, cert. denied, 439 U.S. 921 (1978) ("The Department is not compelled to use any particular method for calculating the rate base, provided that the end result is not confiscatory -- a matter in which the utility bears the burden of proof."); Fitchburg Gas and Elec. Light Co. v. Department of Pub. Utils., 371 Mass. 881, 886 (1977) (In upholding the Department's exclusion of

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Furthermore, the Court has held that in some circumstances the Department is not even bound to adhere to cost-based standards. Id. at 411-412, citing Monsanto Co. v. Department of Pub. Utils., 379 Mass. 317, 320 (1979) (for purposes of cost allocation and rate design, the Court stated that "[w]hile cost of service is a well-recognized basis for utility rate structures, it need not be the sole criterion ... . The Department approved the reduced rate as `an experiment in alternative rate-design.' It may turn out that there are economic factors justifying the reduced rate."); see also Trustees of Clark Univ. v. Department of Pub. Utils., 372 Mass. 331, 336-337 (1977) ("A Massachusetts utility's rates need not be structured on a cost-related basis, unless, after fair warning, the [D]epartment requires that approach.").

The United States Supreme Court ("Supreme Court") has also found that just and reasonable rates can be achieved through incentive regulation. For example, in the context of a case dealing with cost of service ratemaking, the Supreme Court has recognized that state regulators are not bound by a single ratemaking methodology in their determination of just and reasonable rates. In upholding a decision of the Pennsylvania Public Utility Commission to allow an electric utility to recover the costs associated with cancelled nuclear generating units through increased rates, the Supreme Court stated:

> The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors. The Constitution within broad limits leaves the States free to decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public.

Duquesne Light Co., 488 U.S. 299, 316 (1988). In Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the Supreme Court upheld an order of the Federal Power Commission reducing rates of a natural gas company, pursuant to a "just and

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property from the utility's rate base, the Court held "the Department [is] free to select a rule of its choice on this subject as long as the rule was consistently applied, did not have a confiscatory effect, and as long as no special circumstances compelled application of a different rule.") (emphasis in original).

reasonable" standard under the Natural Gas Act, stating:

> We held in Federal Power Commission v. Natural Gas Pipeline Co. [315 U.S. 575, 586 (1942)] ... that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of "pragmatic adjustments." And when the Commission's order is challenged in the courts, the question is whether that order "viewed in its entirety" meets the requirements of the Act. Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.

Federal Power Commission v. Hope Natural Gas Co., 320 U.S. at 602 (citations omitted) (emphasis added).

In a line of cases building on Hope, the Supreme Court has ruled that Constitutional and statutory standards can be satisfied by alternative regulatory schemes that rely on non-cost factors for determining just and reasonable rates. In Wisconsin v. Federal Power Commission, 373 U.S. 294 (1963), the Supreme Court upheld an order of the Federal Power Commission to consider a departure from traditional cost of service ratemaking standards in regulating natural gas producer rates. Regarding the ratemaking authority of FERC, the Supreme Court stated:

> It has been repeatedly stated that no single method need be followed by the Commission in considering the justness and reasonableness of rates...[This] Court has never held that the individual company cost-of-service method is a sine qua non of natural gas rate regulation. Indeed the prudent investment, original cost, rate base method which we are now told is lawful, established, and effective is the very one the Court was asked to declare impermissible in the Hope case less than 20 years ago.

Wisconsin v. Federal Power Commission, 373 U.S. 294, 309-310 (1963) (citations omitted) (emphasis added). The Supreme Court has set forth the minimum requirements for a constitutionally permissible rate regulation scheme:

> [In order for the regulatory scheme to be reasonable, in part, it must] maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable.

In re Permian Basin Area Rate Cases, 390 U.S. 747, 792, 815 (1968).

Therefore, based on its analysis, the Department concludes that it is within the Department's ratemaking authority to modify, refine, or supplement the existing cost-based, rate-of-return regulatory framework, or to adopt new ratemaking approaches, as long as such actions would result in just and reasonable rates, and are consistent with the statutory and constitutional requirements and the guidelines developed in this Order.

C. Department Precedent on Incentive Regulation

In recent years, the Department has continued to seek new ways to ensure that all Massachusetts customers are able to continue to obtain high-quality service at just and reasonable rates. The Department's recent decisions have identified incentive regulation as one tool available to regulators in the transition to a more competitive environment in both the electric and gas industries. For example, in Gas Transportation, D.P.U. 85-178, at 10 (1987), the Department called its decision "a first step in the Department's consideration of the appropriate regulatory framework for an increasingly competitive natural gas market in Massachusetts." As part of this effort, the Department has reviewed and approved several incentive proposals, both targeted and broad. The incentive plans approved by the Department have focused on electric generating unit performance, gas margin sharing, DSM programs, and price caps.

Regarding electric generating unit performance incentives, in 1989, the Department approved an incentive mechanism for BECo's Pilgrim Nuclear Power Station ("Pilgrim") as part of a three-year settlement agreement that resolved both an open base rate proceeding and pending generating unit performance reviews. See Boston Edison Company, D.P.U. 88-28/88-48/89-100, at 5-7 (1989). Various performance criteria were included in a "performance adjustment charge" for Pilgrim's performance.[22] As part of a settlement agreement in BECo's next base rate proceeding, the Department approved an incentive mechanism for some of BECo's fossil generating units that established performance targets for three years and provided incentives to exceed the agreed-upon goals.[23] Boston Edison Company, D.P.U. 92-92, at 11, 15 (1992).

More recently, the Department has approved incentive mechanisms which featured shared benefits between customers and shareholders. In Boston Gas Company, D.P.U. 92-259 (1993), the Department approved the use of margin sharing as an incentive mechanism to allow gas companies to operate in an increasingly competitive market. Specifically, the Department approved a proposal to offer economic incentive rates for certain non-core customers on a two-year experimental basis, noting that this would likely provide benefits to firm customers that were not available under traditional regulation, and that Boston Gas' proposal properly balanced risks and rewards between shareholders and customers (id. at 94-95).[24] Expanding on this incentive mechanism, in Boston Gas Company, D.P.U. 93-60 (1993), the Department

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22 A base component element (incrementally increasing from $20 million to $67.5 million over the three-year term of the settlement) was implemented. This base revenue increase was subject to a performance adjustment charge for Pilgrim I's performance. For example, a bandwidth of 60 to 76 percent capacity factor was established. If Pilgrim's capacity fell below 60 percent in a given year, BECo would be penalized. Conversely, if Pilgrim's capacity exceeded 76 percent in a given year, it would be rewarded. Under the settlement, BECo's revenues would decrease by $1 million for each percentage point of capacity shortfall, not to exceed $30 million. If BECo exceeded its performance goals, it was entitled to a reward of $1 million for each percentage point over the goals, to a maximum of $15 million. The appropriate adjustments are made to BECo's quarterly fuel charge.

23 Under the formula, BECo could earn as much as an additional $4 million for exceeding the agreed-upon performance goals, or incur a penalty of up to $4 million for failure to meet them. The 1992-2000 Pilgrim incentive mechanism approved in D.P.U. 89-100 was continued through the term of the settlement.

24 In its Order, the Department found that Boston Gas had demonstrated that a segment of its non-core market exhibited characteristics of a competitive market and that a more flexible approach was needed to allow Boston Gas to compete in this market; the Department therefore allowed the company to set rates for this segment on an incremental (less than fully-embedded costs) basis. D.P.U. 92-259, at 39-40.

found that it was appropriate to allow margin sharing (over a historical threshold) in the firm non-core, interruptible, and off-system markets. The Department also found that a 75/25 margin sharing between firm customers and shareholders would provide Boston Gas with the incentives and flexibility to compete aggressively in the off-system or interruptible market. D.P.U. 93-60, at 298-326.

The Department has also approved several other margin sharing mechanisms. In Colonial Gas Company, D.P.U. 93-78, at 5-6, 8-9 (1993), as part of a settlement agreement, Colonial Gas was allowed to retain ten percent of all margins associated with non-firm sales (over a historical threshold), and ten percent of margins realized through capacity releases in excess of $2.5 million. In Essex County Gas Company, D.P.U. 93-107, at 4-7 (1993), the Department approved a settlement agreement in which Essex was allowed to retain ten percent of all margins associated with non-firm sales (over a historical threshold). In North Attleboro Gas Company, D.P.U. 94-130-A (1994), the Department approved a 75/25 margin sharing arrangement between shareholders and customers for margins associated with a special bundled sales/transportation contract with a customer who had alternative fuel capability. Most recently, in Berkshire Gas Company, D.P.U. 93-22, at 18-19 (1995), the Department allowed a 75/25 margin sharing arrangement between core customers and shareholders for interruptible sales, finding "margin sharing to be a useful policy instrument in cases where a gas utility is entering new markets or must devote considerable effort to making sales." Finally, as part of its ongoing investigation in D.P.U. 93-141 of interruptible transportation and capacity release, the Department is addressing the issue of whether a ratemaking incentive, such as margin sharing, would be appropriate to encourage gas utilities to make interruptible transportation available in order to promote release of interstate pipeline capacity. See Interruptible Transportation/Capacity Release Generic Investigation, D.P.U. 93-141-A at 3, 7 (Hearing Officer Memorandum on Scope of Proceeding (June 16, 1994)).

In 1986, the Department's Order in D.P.U. 86-36-F initiated and set guidelines for utility DSM programs. The Department directed electric utilities to submit DSM programs for Department preapproval and directed companies to "design the program[s] in such a way that cost recovery is performance-based ... ." D.P.U. 86-36-F, citing D.P.U. 86-36-C at 169. In 1989, in its Order in Massachusetts Electric Company, D.P.U. 89-194/195 (1989), the Department found that a financial incentive for DSM activities was appropriate when incremental energy savings resulted from exemplary performance in pursuing least-cost methods for serving customers.[25] The Department also noted that "it expects [MECo] to move to a performance-based system of cost-recovery ... ." Id. at 174. The dollar value associated with incentives was initially based on a percentage of a given utility's projected return on equity. Id.; see also Boston Gas Company, D.P.U. 90-17/18/55, at 140 (1990); Massachusetts Electric Company, D.P.U. 90-261, at 78-79 (1991). The Department subsequently revised its DSM incentive policy to one that determined the dollar value associated with incentives based on a percentage of DSM program benefits. See Boston Gas Company, D.P.U. 90-320 (1991); Boston Edison Company, D.P.U. 90-335 (1992).

With regard to price cap mechanisms, the Department approved a weighted-average price cap in AT&T Communications of New England, Inc., D.P.U. 91-79 (1992). In considering price caps as a transition mechanism to a competitive environment, the Department noted that "one of the Department's goals in establishing a regulatory framework for the telecommunications industry is to ensure that the framework is flexible enough to react to changes in the ... marketplace in the future." D.P.U. 91-79, at 18-19. The Department further stated that "in general, regulation serves as a surrogate for market forces in markets not characterized by effective competition." Id. at 41.

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25 The Department concluded that meeting 50 percent of DSM program goals would constitute average performance, and set a threshold of 50 percent for megawatt and megawatthour savings, with savings above this level subject to incentive payments. D.P.U. 89-194/195, at 177. The Department allowed MECo a bonus equal to 100 basis points on return on equity if it met its program targets. Id. at 177-178.

Finally, as we noted in the Order opening this case, this inquiry takes place in the context of a number of Department cases which are addressing transition issues for utilities, arising from regulatory changes and the increasing influence of competitive market forces. See, e.g., NYNEX, D.P.U. 94-50; Recovery by Massachusetts Gas Utilities of FERC Order 636-Related Transition Costs, D.P.U. 94-104; Interruptible Transportation/Capacity Release Generic Investigation, D.P.U. 93-141; Massachusetts Electric Company, D.P.U. 94-102 (investigation into claim of stranded investment); Notice of Inquiry into Electric Industry Restructuring, D.P.U. 95-30. The Department is aware of the need to identify and coordinate the effects of these various initiatives on each other and to ensure that any short-term reforms are consistent with overall long-term goals and trends in the industries. Specific issues raised by the commenters regarding the coordination of different regulatory changes have been described in Section II, supra, and are addressed below.

D. Evaluation of Incentive Proposals

1. Introduction

In this Section, the Department establishes the standard of review to be applied to incentive proposals, discusses incentive regulation generally, and sets forth the criteria and procedure for submitting specific proposals.

2. Standard of Review

The focus in this docket is on incentive regulation as an alternative to COS/ROR regulation within the broad context of the Department's current regulatory scheme. Any incentive proposal would therefore be subject to the standard of review of G.L. c. 164, § 94, which requires that rates be just and reasonable. See Section II.B., supra. As in a rate case under G.L. c. 164, § 94, the burden of demonstrating that a particular incentive proposal is consistent with this standard is on the proponent; a proponent must demonstrate that the proposal is consistent with the Department's goal of "provid[ing] a framework that ensures that the utilities it regulates provide safe, reliable, and least-cost service." Notice of Inquiry at 1, citing Mergers and Acquisitions, D.P.U. 93-167-A at 4.

Most of the comments filed on this question focused on the need for specific criteria for designing and evaluating particular proposals consistent with the above standard; the Department addresses this issue below.

3. General Assessment of Incentive Regulation

Although very little empirical data exists on its long-term effects, five broad classes of potential benefits are associated with incentive regulation: improved X-efficiency; improved allocative efficiency; improved dynamic efficiency; facilitation of new services; and reduced regulatory and administrative costs.[26]

X-efficiency is broadly defined as the degree to which a firm maximizes the production of goods and services that are produced with any given combination of inputs. In other words, the question is whether the firm is getting as much out of its resources as it can. Another way of thinking about this is to ask whether the firm could do more with less. If a firm does not operate with maximum attainable X-efficiency, the firm and society lose the potential benefits of increased output at no additional cost. Allocative efficiency is the ability to provide service using the optimal combination of inputs, thereby minimizing total cost. Dynamic efficiency is reflected in the increase in productivity, or the improved ability of firms to create value with given resources, resulting from innovation, and includes making cost-reducing investments in areas such as research, reorganization and capital equipment, that result in the provision of service at the lowest possible cost over time. All three kinds of efficiencies, when achieved, result in better overall value for customers.

By giving utilities a financial stake in improved efficiency and a greater share of any of the costs savings that result, incentive regulation can create a positive incentive over COS/ROR

[26] A useful discussion of these issues can be found in "Regulatory Practices and Innovative Generation Technologies: Problems and New Rate-Making Approaches," The National Regulatory Research Institute, Ohio State University (March 1994).

regulation that can simultaneously deliver service to customers at lower prices, and encourage innovative services, thereby benefiting customers and firms alike.

The Department recognizes fully that all incentive plans, and particularly those according a utility increased pricing flexibility, must be carefully designed. First and foremost, any plan must credibly assign benefits to customers, whether in the form of lower prices or increased service, that improve on what would have been offered under current regulation. Second, a plan should not encourage or allow cross-subsidization or other anti-competitive behavior that could inhibit or suppress emerging competition. Finally, the likelihood of exceptional reward and improved financial integrity for the firm, if its performance is good, is essential to any plan. Truncating a firm's rewards unduly risks the benefits to customers that well-designed plans can offer.

The Department understands that, where financial incentives are based on a benchmark or index, an otherwise unconstrained utility could have an incentive to divert resources from other goals, such as service quality and reliability, DSM, environmental management, and low-income programs, in order to enhance its performance on the benchmark criterion. It is possible, however, to design incentive plans that ensure the continued pursuit of these goals, and we expect that all plans we approve will have satisfactorily addressed these issues.

The Department also recognizes that structural constraints, particularly those based in statute, may limit the initial scope of an incentive plan in some instances. For example, the recovery of fuel and gas costs is so governed in part. We encourage the innovative development of incentive plans to address these issues. We acknowledge, however, that some structural changes may be needed to realize the full potential of incentive approaches.

Finally, under incentive regulation, administrative and regulatory costs may be reduced, because the ratemaking cycle is lengthened or eliminated altogether, and reasonableness reviews may be limited to certain predetermined criteria, or "triggers." It is uncertain whether administrative cost savings can be achieved by implementation of incentive mechanisms in the short term, because it is possible that costs avoided by eliminating rate cases will be replaced by initial monitoring and evaluation costs. But, at a minimum, once a plan is adopted, litigation costs incurred by utilities, intervenors, and the Department should be reduced.

4. Criteria for Submission of Incentive Proposals

a. Introduction

The Department emphasizes that its willingness to consider incentive regulation is consistent with its traditional goals and reaffirms its obligation and intention to serve the public interest. The Department has concluded that the expanded use of well-designed incentive regulation mechanisms can be more responsive to customers' needs and the changes in the marketplace, while also meeting its other statutory obligations.

Well-designed incentive mechanisms should provide utilities with greater incentives to reduce costs than currently exist under traditional COS/ROR regulation. Incentive regulation recognizes the legitimacy of profit as an important motivator for utilities, and a utility that knows it will be rewarded for efficiency and penalized for inefficient operations will take a more aggressive approach to control costs. Notice of Inquiry at 4, n.2.

Traditional COS/ROR regulation does not provide a sufficient link between a utility's performance and its financial rewards for two reasons. First, under traditional COS/ROR regulation, a utility that introduces new technologies and achieves cost reductions or other improvements may experience only short-term increases in profit, because in a subsequent rate proceeding, its overall cost of service (and thus its revenues) will be reduced dollar for dollar to recapture the revenues. The Department recognizes that regulatory lag between the implementation of a cost-cutting measure and its reflection in rates can provide utilities with some motivation to reduce costs during the period between its base rate cases. However, to the extent that a company's earned return significantly exceeds the level allowed in its most recent base rate case, the company may be required, under G.L. c. 164, § 94, to reduce its rates. Traditional regulation therefore reduces the incentive for a utility to undertake cost-cutting activities.

Second, under traditional regulation, certain utility expenses (e.g., costs associated with fuel, purchased power, and gas supplies) are passed through in full to customers.[27] These existing recovery mechanisms neither expose utilities to the risks associated with market changes, nor reward them for managing those risks effectively.

In the past, the Department has relied on adjustments to the allowed return on equity as a means to reward efficiency and penalize utilities for inefficient operations. Massachusetts Electric Company, D.P.U. 92-78, at 115 (1992); Boston Edison Company, D.P.U. 85-266/271, at 172-173 (1986). However, this represents at best an after-the-fact approach towards inducing efficiency in utility operations. Well-designed incentive mechanisms should remove the disincentives associated with traditional ratemaking by allowing both customers and shareholders to benefit. Additionally, a well-designed incentive mechanism should provide a utility with the opportunity to earn greater rewards in exchange for the assumption of greater risk.

b. Criteria for Evaluating Incentive Ratemaking Proposals

i. Introduction

As described in Section II, supra, commenters generally agree that specific incentive mechanisms should reflect the varied circumstances faced by each gas and electric utility under the Department's jurisdiction. The commenters also recommend that the Department not prescribe a specific mechanism for all utilities (Bay State Reply at 4; Berkshire Reply at 2; Boston Gas at 7-8; COM/Energy Reply at 5-6; EECo at 17; WMECo Reply at 5). At least for the present, the Department agrees with these recommendations. The Department will evaluate

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[27] Although the cost-recovery mechanism for certain expenses, such as fuel and purchased power costs, are prescribed by statute, it may be possible to treat such costs within an incentive plan on a voluntary basis.

and review incentive proposals on a utility-specific basis, consistent with the general principles and guidelines stated in this Order.

The Department recognizes that in order for utilities and other interested parties to develop individual incentive proposals, well-defined standards and filing requirements are necessary. As a general proposition, a petitioner seeking approval of an incentive proposal shall be required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe and reliable energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. The Department provides more specific evaluation criteria below.

(a) <u>Consistency With Department Regulations, Statutes and Governing Precedent</u>

Incentive mechanisms must comply with Department regulations, unless accompanied by a request for a specific waiver. If a petitioner's incentive proposal is inconsistent with Department regulations, the proposal must describe the particular element or elements of the incentive mechanism that conflict with regulatory practice, the reason why a waiver is necesssary, and the petitioner's proposed method of addressing this conflict.

Because incentive mechanisms that would require changes in statutes or governing precedent would require more time and effort to achieve, the Department strongly prefers that incentive proposals also comply with these requirements. If a petitioner's incentive proposal is inconsistent with statutory or case law requirements, the proposal must describe the particular element or elements of the incentive mechanism that conflict with the law, the reason why a change in statute or precedent is necessary, and the petitioner's proposed method of addressing this conflict. A petitioner must submit the text of any proposed legislation intended to resolve the conflict.

(b) <u>Consistency with Market-Based Regulation and</u>

Enhanced Competition

Incentive mechanisms must complement the ongoing movement towards a more market-based utility framework. Fundamental changes in the marketplace for energy services likely will result in lower costs and the provision of more highly valued services -- two of the Department's central objectives. Where customer choice can be enhanced, the Department will continue to rely on expanding the number of market-based solutions. The Department recognizes, however, that competitive markets cannot be relied upon for every aspect of utility service (e.g., transmission and distribution). Where competitive markets do not exist, the Department continues to recognize its obligation to oversee and protect against the detrimental exercise of market power, albeit through more flexible regulatory mechanisms than have been relied upon to date.

Incentive mechanisms should be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services. Each incentive proposal should discuss the area of service targeted by the plan (monopoly, potentially competitive, or both) and discuss why the company chose to target that area of service. Each proposal should also include an explanation of how it is consistent and/or complementary with the transition toward a more competitive market for energy services. In addition, incentive proposals should avoid the cross-subsidization of competitive services by revenues derived from the provision of monopoly services.

(c) Safeguard System Integrity, Reliability, and Current Policy Objectives

A number of commenters express the concern that the implementation of incentive regulation may result in compromises in safety, reliability, and other public policy considerations. Specifically, concerns are raised that the obligation to serve, as well as the Department's policies in the areas of DSM initiatives, low-income rates, environmental externalities, geographically averaged rates, safety, and reliability standards may be incompatible with a price-driven, broad-based incentive program (See COM/Energy at 15).[28] Bay State requests that the Department offer guidance on this issue by prioritizing those policy objectives that should be retained under incentive regulation (Bay State Reply at 5).

While the primary focus of any incentive proposal should be to achieve cost reductions, the Department continues to recognize its mandate to ensure the continued delivery of safe and reliable service to the public. Contrary to the impression conveyed in the comments of some parties, incentive regulation does not signal the end of regulatory oversight of gas and electric utilities, but represents what may be a more effective means of achieving these and other goals than traditional COS/ROR regulation. The Department will not accept incentive proposals that result in reduced safety, nor will it permit incentive proposals to be used as a vehicle to weaken service reliability or existing standards of customer service. Furthermore, the Department insists that existing standards of customer service must be maintained or enhanced under any incentive proposal. In those incentive regulation petitions involving electric utilities, petitioners must also incorporate the fact that an obligation to serve customers continues to exist.

The Department recognizes that there are some policies, for example those regarding DSM and low-income rates, that may be amenable to continuation under incentive regulation through a means other than that relied upon at present. To the extent that an incentive regulation proposal seeks a change in the way these policies are implemented, the proposal

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[28] Additionally, CLF contends that the Department is required by law to conduct an environmental impact study on any proposed incentive ratemaking rule which would eliminate or erode existing environmental protections (CLF Reply at 2-5). Because the Department is not addressing in this docket the merits of the incentive proposals put forth by BECo, DOER, or the Energy Consortium, we find it unnecessary at this time to address the need for an environmental impact study under incentive regulation. The Department stresses that it will comply fully with all applicable laws when undertaking a review of any incentive proposal.

should be explicit on how these issues are addressed.[29]

(d) Rewards Utility Performance and Addresses Exogenous Costs

A number of commenters urge the Department to recognize the importance of continuing to allow the recovery of past, prudently incurred costs that were approved by the Department. Other commenters support a separate recovery of costs that are beyond the control of management ("exogenous costs"). The commenters state that incentive mechanisms that did not incorporate separate cost-recovery for these particular costs could hamper a utility's ability to maintain its financial integrity. The Department has carefully considered the comments raised in this context, and their implications for incentive regulation.

Traditional ratemaking affords utilities a reasonable opportunity to recover prudent and verifiable expenditures made pursuant to legal obligations. Incentive regulation, on the other hand, seeks to harness the profit motive to further specific regulatory goals and to move away from the traditional concept of "cost recovery." The Department notes that the concept of "cost recovery" embodied in many comments runs directly counter to the performance-based, regulatory approach under consideration in this proceeding. Because incentive mechanisms are intended to more closely replicate market forces, incentive proposals that focus excessively on cost recovery issues may miss the point behind incentive regulation.

However, there may be some costs which are beyond the control of the utility. These may include, for example, changes in income tax rates, changes defined by governmental accounting standards boards, and regulatory, judicial, or legislative changes that impact cost centers. Petitioners may seek to have these or similar cost categories treated as exogenous

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29 WMECo proposed the use of a "universal service charge" as a means to cover costs associated with public policy responsibilities and stranded costs (WMECO Response to Department Question 3). While the Department does not rule out the use of some access charge mechanism as a method of resolving potential conflicts between incentive regulation and public policy goals, it is skeptical about the practicality or efficacy of access charge-type solutions.

costs. The Department will examine the propriety of any exogenous cost categories on a case-by-case basis. If a utility seeks to have specific cost recovery issues addressed within the context of an incentive proposal, that utility must affirmatively demonstrate the necessity of any distinct plan components that address cost recovery issues by presenting evidence on (1) the nature of any exogenous costs for which specific rate treatment is sought, and (2) the reasons why these costs should be treated in a different manner than other utility costs that are subject to the incentive mechanism.

(e) Focus on Comprehensive Results

Although the Department does not prescribe or endorse a specific incentive mechanism in this Order, broad-based mechanisms appear in general to better complement a competitive marketplace. The Department acknowledges that there may be some areas of utility operations, such as DSM and environmental compliance, that broad-based incentive mechanisms may not be able to fully address. In these instances, the use of targeted incentives within the context of a broad-based incentive proposal may be appropriate. Petitioners seeking to include targeted incentive mechanisms as part of broad-based incentive schemes must identify the specific policy objective intended to be met by the targeted incentive, demonstrate why a broad-based proposal otherwise fails to meet those particular needs, and show that any inconsistency between the plan and its overall goals is minimized.

The Department does not wish to preclude targeted incentives, per se, but encourages petitioners to demonstrate how targeted incentives would complement a comprehensive plan to control overall costs and improve service.[30] If a utility opts to submit a narrowly-targeted incentive proposal, the petitioner must satisfactorily address the concern that it may create

[30] Furthermore, targeted incentive mechanisms may be required in a marketplace that provides unbundled services. If unbundling is a prerequisite to a more competitive marketplace, targeted mechanisms (submitted in conjunction with an overall broad-based incentive plan) may be superior to a broad-based mechanism that restricts unbundling.

perverse incentives.

(f) Incorporates Well-Defined, Measurable Indicators of Performance

Proposed incentive mechanisms should be designed to achieve specific, measurable results. To that end, incentive proposals should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation. Broader indicators are preferred. Performance indicators should be tied to the stated goals of a program and be consistent with the Department's regulatory goals. The indicators should be designed to assist parties in evaluating the effectiveness of an incentive program. Performance indicators to evaluate a program's effects on safety, reliability, and service quality must also be incorporated in any well-designed incentive mechanism.

(g) Consistent with Accounting Standards and Acceptable within the Financial Community

The Department concurs with those commenters who state that GAAP would not necessarily adversely affect incentive proposals. Proposals that incorporate the guidelines laid out herein can allow utilities to access the capital markets at reasonable cost. In formulating specific proposals, utilities should, if they consider it necessary, discuss the implications with respect to the continued application of FASB requirements and GAAP. One useful resource for evaluating the accounting impacts of incentive proposals would be results from the work performed by the EITF.

There is a significant body of opinion in the comments that a well-designed incentive proposal that incorporates clear objectives, consistently applied incentives, and an equitable sharing of potential risks and benefits between customers and shareholders would be viewed favorably by investors. On this basis, the Department finds that the benefits of a plan that meets these criteria would outweigh any perceived short-term risk to a utility adopting an incentive plan.

5. Implementation and Administration of Incentive Programs

a. Administrative Simplicity

As stated above in Section III.E.2, one potential benefit of incentive regulation is a reduction in regulatory and administrative costs. Incentive mechanisms should provide a more efficient regulatory approach. In designing proposals, utilities should give due consideration to the need for administrative simplicity. The Department expects that proposals will demonstrate a utility's initiative and allow the Company to manage the program responsibly. The Department does not wish to engage in burdensome, complicated, and time-consuming reviews of company management. The Department does expect, however, that proposals will outline how performance will be tracked and evaluated over time by company management and other interested parties. Incentive plans should present a timetable for the program's implementation and specify program milestones and/or a program tracking and evaluation mechanism.

b. Design and Consideration Process

The Department strongly encourages all jurisdictional gas and electric utilities to devise and propose incentive plans. Utilities may file incentive plans either as unilateral petitions or as joint settlements. Utilities that are now precluded from filing a base rate case because of the terms of a settlement should act within the parameters of their settlement and consider filing incentive plans once the restriction has elapsed. The largest utilities that are not so restricted should commence the incentive plan design process as soon as possible. The Department will endeavor to issue a final decision on any incentive proposal within six months, in keeping with the statutory six-month review period accorded for traditional base rate proceedings.

The Department notes that incentive regulation represents one means to attain the Department's stated regulatory goals. Thus, the Department will not require all gas and electric companies to submit incentive proposals at the present time. However, any utility that does not file an incentive program following the issuance of this Order will be required to demonstrate with full specificity, in its next base-rate case, how it is seeking to achieve more efficient operations, better cost control, and lower rates, and to explain why it has not submitted an incentive proposal for these purposes. See Massachusetts Electric Company, D.P.U. 92-78, at 19-20, 25-26, 30 (1992) (the Department indicated that, as an aid in determining the reasonableness of cost adjustments, it would compare a utility's costs in relation to other New England investor-owned utilities and to companies in the utility's service territory that compete for similarly-skilled employees and other resources). Companies with incentive programs will likely serve as a comparison group to evaluate the effectiveness of utilities without incentive programs.

F. Conclusion

As explained above, an incentive mechanism should (1) be consistent with Department regulations, statutes, and governing precedent; (2) be consistent with market-based regulation and enhanced competition; (3) safeguard system integrity, reliability, and current policy objectives; (4) reward utility performance and address exogenous costs; (5) focus on comprehensive results; (6) incorporate well-defined, measurable indicators; (7) be consistent with accounting standards and acceptable within the financial community; (8) have a minimum time horizon to give the incentive plan enough time to achieve its goals; (9) provide for re-evaluation of the program at least once during its term to monitor goal attainment and make required modifications, as necessary; and (10) be administratively simple. In providing this enumeration, the Department does not intend to deter petitioners from proposing other appropriate criteria or methods to achieve the Department's goals.

IV. ORDER

Accordingly, after due notice and consideration, it is

ORDERED: That future incentive proposals shall be reviewed in a manner consistent with this Order.

By Order of the Department,

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Kenneth Gordon, Chairman

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Mary Clark Webster, Commissioner