# National Regulatory Research Institute

# Overview of Regulatory Incentives in the Context of Public Policy Goals

**Prepared for the Colorado Public Utilities Commission**


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## I. Overview

The purpose of regulation is to align private behavior with public interest goals. In utility regulation, those goals include ensuring high-quality service to customers at reasonable rates. Rates are reasonable if they: reflect prudent cost, innovation, and responsiveness to current needs and future challenges while providing a fair opportunity for shareholders to earn a return comparable to returns earned by shareholders in other businesses with comparable risks.

To achieve the necessary alignment, regulators first must establish clear goals; then identify regulatory devices that induce utility performance consistent with those goals. Subsection A of this Overview describes six goals which have received emphasis in discussions between researchers at the National Regulatory Research Institute and the members and staff of the Colorado Public Utilities Commission. Subsections B, C, and D then provide an overview of the general categories of inducements, specific regulatory devices, and criteria for assessing their effectiveness in achieving the Commission's goals. Subsection E provides an outline of the structure of this report.

### A. The Commission's Goals

The Commissioners and staff have articulated six policy goals of energy utility regulation in Colorado:

#### 1. Ensure adequate physical infrastructure to provide reliable electric service using facilities that meet the Commission's multiple objectives at reasonable cost.

This goal includes capacity replacements and additions (for generation, transmission, and distribution), taking into account purpose of capacity (e.g., base load vs. intermediate vs. peaking), resource type (e.g., fossil vs. renewable), and ownership mix (e.g., buy vs. build). The goal also requires attention to reliability, climate change, price stability, and energy independence.

#### 2. Ensure cost-effective demand-side management and energy efficiency.

This goal is a sibling of cost-effective infrastructure investment. Together, the two types of investment must produce a cost-effective solution to the challenge of meeting customer demand. We have separated it out because the regulatory devices necessary to achieve this goal differ. The type, timing, and amount must take into account customer readiness, cost, and administrative feasibility, and must be determined in conjunction with the physical capacity needs noted in Item 1 above.

### 3. Prepare for climate change.

There is uncertainty about the shape, timing, and cost of federal and regional climate change policies, but this uncertainty is not grounds for inaction. Governor Ritter has asked the PUC to play a major role in meeting the state's carbon reduction goals as expressed in the Climate Change Action Plan.

### 4. Induce cost-effective management practices that keep rates reasonable.

These management practices can relate to both operational efficiency (e.g., power plant management, fuel purchasing, labor deployment, hedging) and financial efficiency (e.g., the proper mix of types of capital.)

### 5. Maintain excellent service quality.

Quality of service is a goal unto itself and a constraint condition on both long-term and short-term cost minimization. The dimensions of service quality include various reliability measures, customer responsiveness, outage minimization and management, and power quality.

### 6. Spur technological innovation.

Innovation is core to achieving each of the other goals. It is worth separate treatment because utilities and their regulators face a convergence of challenges requiring some departure from past practices.

For each goal, this memorandum will address three questions: (1) What general regulatory approaches are available to advance each goal? (2) What specific regulatory devices are available? and (3) For each type of regulatory action, what are its strengths and weaknesses, in terms of effectiveness and feasibility? We elaborate on each question next.

## B. Which general regulatory approaches are available?

By "regulatory actions" we mean actions by either the Commission or the Legislature. One way to categorize regulatory actions is to apply a three-step sequential analysis.

### 1. Mandatory or voluntary?

The first question is whether the Commission (or Legislature) has made a particular utility practice mandatory or voluntary. An example of a mandate is where a Legislature has mandated a particular amount of renewables production or purchase, or where a Commission has mandated a specific quantity and schedule for tree-trimming. An example of a voluntary situation is where the Commission or Legislature has said, in effect, "The utility needs more transmission," but has not mandated a specific amount or location.

### 2. Cost recovery only, or profit enhancement?

Any utility action, whether mandated or voluntary, deserves an opportunity to recover cost. For some utility actions, the Commission or Legislature may wish not only to allow cost recovery but to increase the utility's return on equity.

### 3. If cost recovery only, guaranteed recovery or opportunity to recover?

Cost recovery options have two distinct dimensions: timing and certainty. Concerning timing, cost recovery can occur at the time cost is incurred (e.g., expense adders for expenses) or at the next rate case (test year treatment of known expenses). Concerning certainty, there can be the opportunity to recover cost (e.g., the traditional treatment in setting base rates, where an expected expense is reflected in the revenue requirement but where actual recovery depends on the utility's total experience with sales and expenses); or there can be a guaranteed recovery of cost (e.g., fuel cost adders that "true up" actual costs).

These distinctions are worth remembering because cost recovery mechanisms are sometimes confused with incentive mechanisms. Some cost recovery mechanisms are created to allow a utility to recover the costs associated with a legislative or regulatory mandate. No explicit encouragement is offered or necessary; the mandate is the inducement. One of the challenges associated with the mandate-plus-cost-recovery approach is ensuring that the costs incurred were reasonable and the recovery mechanism did not create an indifference to cost minimization.

## C. What specific regulatory devices are available?

Once one or more of the three general approaches have been chosen, multiple regulatory actions are available. These actions are not mutually exclusive; the Commission can choose more than one. Here are seven categories:

1. Traditional rate base regulation, unmodified. We discuss this concept, and its cost-based cousins rate cap and revenue cap regulation, in sections I.A, B, and C below.

2. Adjustment clauses and adders for targeted expenses. Examples are fuel cost purchases, environmental compliance costs, nuclear license cost adders, "system benefits charges," adders for transmission and distribution costs, and flow-through of renewable purchases.

3. Cash flow assistance for targeted capital expenditures. Examples are construction work in progress (CWIP), accelerated depreciation, and recovery of pre-commercial costs.

4. Guarantees of later cost recovery. Examples are pre-approval of utility actions, such as resource decisions or demonstration projects; approval of

deferral accounts; guarantee of cost recovery in case of later project abandonment or failed demonstration projects; and securitization.

5. Rewards and penalties based on indices or triggers, with adjustments for state-specific facts). Examples include:

   a. price cap pricing and index pricing, including performance benchmark models that reward or penalize utility based on comparison of its operating costs to industry indices (with proper adjustments for state-specific facts)

   b. pricing based on operating ratios

   c. service quality triggers

6. Profit adders for particular actions (e.g., FERC adder to ROE for certain transmission investments)

7. Adjustments that address deviations from utility profit maximization arising from regulatory objectives. Examples include:

   a. Build vs. buy adjustments, such as an increase in authorized cost of debt to reflect perceived risks associated with long-term power purchases

   b. "Lost revenues" adjustments, to address profit shrinkage due to the substitution of power purchases for plant construction

   c. "Lost revenues" adjustments, to address foregone capital cost recovery or profit shrinkage arising from sales reductions due to DSM or energy efficiency programs

   d. Decoupling profits from sales, to create profit comparability between demand and supply actions or capital-intensive and non-capital intensive actions

Another regulatory incentive mechanism is the management audit, in which the utility pays to have a management audit performed under the supervision of the commission. Findings from that audit can be used to assess the reasonableness of costs in base rate cases and to set efficiency targets or standards. The knowledge that management audits are going to occur on some reasonable time schedule can encourage utility cost-effective behavior.

## D. For each type of regulatory device, what are its strengths and weaknesses, in terms of effectiveness and feasibility?

To address this question, we will use the following criteria, among others:

**Effectiveness criteria**

1. Is it the least-cost means of achieving the desired outcome?
2. Is each incentive connected to a well-defined obligation, or does the action instead give the utility extra compensation for activities which are part of the normal utility service obligation compensated with normal return on equity?
3. Does it reduce uncertainty and risk?
4. Is it susceptible to gaming?
5. Can we measure its effectiveness after the fact?
6. Does it cause conflict with other goals?
7. Is it possible to measure the effect of the regulatory measure?

**Feasibility criteria**

1. Does the Commission have access to the expertise and information necessary to implement the action?
2. Is it administratively costly?
3. Can regulators modify the action, or is the action irreversible?

The document will discuss the options using logical analysis, while referring to examples implemented by states. The discussion of the examples is a general summary. More detailed analysis of other states' options can occur when the Commission expresses a particular interest in that option.

For purposes of analytical clarity, this document analyzes each possible regulatory action in isolation from the others. The real world is different. Management incentives and customer incentives can act in concert or in conflict. Customer incentives, i.e., methods to induce customers to consume efficiently, are not part of this proceeding or this report. There is, however, a linkage between management incentives and customer incentives. The most direct means of causing efficient customer behavior is efficient rate design. Rates that provide accurate signals about the true cost of consumption (long-term marginal cost including externalities) will provide management with the most accurate information about how to plan the system's resources. Paying management money to act efficiently will not succeed if millions of consumers face rate designs that invite inefficiency.

Coordination between utility and customer incentives, therefore, is necessary for the effectiveness of each. A question for the Commission to address, after assessing regulatory measures in isolation, is how to build a system of measures that, taken together, constitutes a coherent, mutually consistent, and nonredundant approach.

### E. Organization of this report

Section II describes the basic regulatory models. Section I.IA begins with the core regulatory models: cost of service, price caps, and revenue caps. Section II.B discusses modifications regulators commonly make to those models, such as adders and adjustment clauses, both general and targeted. Section II.C discusses certain concepts useful in assessing the effectiveness of these measures—namely, regulatory lag, allocation of benefits between ratepayers and shareholders, tradeoffs and secondary effects, information asymmetry, and gaming.

Section III then turns to each of the Commission's six goals: adequate physical infrastructure, cost-effective demand-side management and energy efficiency, climate change, cost-effective management practices generally, service quality, and technological innovation. For each of these goals, we address two questions: (1) What regulatory inducements are available? and (2) What are their strengths and weaknesses?

## II. The core regulatory models and their modifications

### A. The three core models

The three core regulatory models currently in use are: rate base - rate of return regulation, also known as cost-of-service regulation; price caps; and revenue caps. There are differences between the behaviors that these various mechanisms encourage. The discussion of these general regulatory mechanisms will focus on these nuances, as the imperfections of these models is what often leads to the introduction of additional incentives, sometimes in an ad hoc manner.

An Appendix discusses mathematical descriptions of the three models.

#### 1. Cost-of-service model

The cost-of-service model is the standard starting point for traditional economic regulation of a natural monopoly (declining average and marginal costs) in the United States. A regulatory commission, after a full evidentiary rate case, determines a utility's revenue requirement. The revenue requirement consists of a utility's just and reasonable operating expenses (e.g., labor, fuel, and regulatory assessments but not expenses associated with lobbying, country club memberships, or promotional advertising), straight-line depreciation, and return on its used and useful assets or rate base and taxes. Revenues or expenses from the test year are normalized (set to reflect normal conditions such as weather) and annualized (set to reflect a full year of a change that occurred partway through the test year).

Rate base is a compilation of the utility's used and useful assets, such as pipes, wires, generating equipment, land, working capital, buildings, vehicles, and computers—essentially, anything that the utility lists as an asset on its balance sheet that is needed to provide service to its customers. The traditional value of these assets for ratemaking purposes is depreciated original cost. For most but not all capital expenses, assets that are under construction (*construction work in progress* or CWIP) are not included in rate base. Utilities accumulate a deferred return on their CWIP called an *allowance for funds used during construction* (AFUDC), which is capitalized and included as part of the total construction cost when the project is placed into rate base.

A rate of return is applied to rate base to create an authorized return. The rate of return is a weighted average of a utility's cost of debt and equity. The cost of debt is determined objectively by referencing the interest rates on all of the utility's outstanding bonds. The cost of equity is based on judgment, with the central question being, "What authorized return is necessary to attract and keep the amount of shareholder equity deemed necessary to meet the company's public service obligations?" There are multiple methods for calculating the cost of equity. Common to all of these multiple methods is the goal of ensuring that if the company operates prudently and faces predicted conditions, its shareholders will earn a return comparable to what they would earn had they invested in other companies facing comparable business risks.

The last component of the revenue requirement is income and gross receipts taxes. Income taxes are based upon tax rates and the authorized return on equity. All other costs, whether they be non-cash expenses such as depreciation, the interest on bonds, or fuel, are assumed to be dollar-for-dollar offsets of all other revenue. Income taxes are not the amount that is actually paid by the utility. Taxes on gross revenues are then added on top of all other revenue to produce the annual revenue requirement...

The traditional cost basis for the revenue requirement is historic cost. Regulators identify a previous 12-month period, known as the *historical test year*. Then they make "pro forma adjustments" to those figures to normalize atypical costs and revenues and to annualize costs and revenues that will recur in the future but occurred only partway through the test year. Regulators also might make adjustments for "known and measurable" variances from the historic test year figures. Regulators who use a *future test year* use figures representing their expectations of future costs and revenues, but those expectations still will have some basis in experience from prior years.

After determining the annual revenue requirement, the regulator sets rates such that if the predicted levels of sales occur, the utility will sell enough product to produce revenues equal to the annual revenue requirement. The traditional way of designing rates to recover the allowed revenue requirement is through some type of average cost pricing where the revenue requirement allocated to a class is divided by usage in the class, producing rates.

The typical tariff is a standard two-part tariff with a fixed and variable component. In many rate designs, there is not a full alignment between the utility's fixed costs and the tariff's fixed charge. Rather, rates often recover some fixed costs through the variable charge. As we will see in section III.B.1, this method of cost recovery means that the utility faces a conflict between recovering its fixed costs (including profit) and reducing sales in the name of energy efficiency. This status quo "coupling" of profits to sales is a reason for efforts to "decouple."

Some of the elements that go into calculating a revenue requirement are interrelated; changing one element can change other elements. Changing the depreciation rate causes changes in the rate base, income, and taxes. Below is a simplified equation that lays out the calculation discussed above.

***Revenue Requirement = expenses + depreciation + taxes + (rate base* x *rate of return)***

The cost-of-service model's purpose is to enable the utility to recover its variable and fixed costs (including reasonable profit). It works best when actual costs and revenues are similar to those predicted from the test year. Volatile fuel prices, general inflation, changes in demand, changes in mandates such as environmental regulations, and major technological breakthroughs can all cause financial results that diverge from predictions. As discussed in section II.B.1, regulators can address some of these deficiencies using regulatory tools such as automatic adjustment clauses.

The strength of the cost-of-service model is its emphasis on limiting utility revenues to those necessary to recover costs plus reasonable profit, thus preventing the excess profits that would have existed if the monopoly had not been regulated. The concerns expressed about the cost-of-service model include:

1. There is insufficient incentive toward general cost-effectiveness because (a) prudence review is infrequent and difficult to achieve due to the information and expertise asymmetry between regulator and utility, and (b) cost reductions initiated by management seem to flow only partially to shareholders (between rate cases) because in subsequent rate cases the regulator will lower the revenue requirement to reflect the lower costs arising from management efforts.

2. Management will favor capital projects because they enter the rate base and thus increase profitability. Moreover, regulatory errors in setting return on equity can distort management decision-making: high authorized excess return on equity produces overinvestment, whereas low authorized return on equity produces underinvestment.

3. The return-on-equity feature is an imprecise tool for rewarding or penalizing performance. Unless regulators set explicit targets for quality of service or compliance with environmental mandates, utilities have to guess at the level of performance that will win them high authorized returns.

4. There is potential bias against demand-side resources such as energy efficiency, distributed generation, behind-the-meter renewable resources, and demand-side management because income is linked to sales.

### 2. Price cap model

The price cap model tries to address concerns (1) through (3) listed under the traditional rate of return model. The price cap approach tries to extend the period between rate cases to at least 3 and sometimes 5 years. Doing so increases the regulatory incentive for operating cost effectiveness because the utility can retain the profits associated with cost reductions for a longer period (this period is often referred to as "regulatory lag"). Price cap calculations often start with the same cost and sales information used in a cost-of-service rate case. The regulator then tries to set a price, based on (but not confined by) this cost information. That price then serves as a cap for a number of years. An alternative approach to using cost data as a basis for price-setting is to use information from other utilities to create a benchmark basis for a price cap. Adjustment factors for inflation and productivity allow the regulator to extend the period between rate cases without causing excess returns or revenue attrition. The goal is to increase management's incentive to minimize costs by reducing the take-backs associated with cost reassessments at rate cases, while also allowing ratepayers to benefit from management's execution of its duty to operate efficiently.

The general formula for a price cap model is:

$$Price_{Year1} = Price_{Year0} * (1+(i-x)) +/- z$$

where i is a measure of inflation, x is a productivity adjustment, and z refers to items that are excluded from the rest of the calculation.

Price cap models usually include a set of performance standards linked to quality of service. This approach gives the utility explicit incentives to meet or exceed service quality standards. The rationale for injecting explicit standards into the price cap model is that the cost minimization incentive is greater in the price cap model compared to the cost-of-service model. The targeted incentives used in price cap models could be applied to cost-of-service regulation and generally are part of revenue cap models.

Because the price cap model sets prices rather than revenues, there is no authorized return on equity based on rate base. This difference from the traditional revenue requirement model eliminates the latter model's bias towards capital intensive decisions. Nor does the price cap prevent excess or insufficient profits. The price cap does permit the utility to set prices below the cap to deal with market competition issues, especially from other energy sources. Price reductions that are not tied to competition are unlikely, as the natural tendency of the monopoly is to set prices higher than the competitive market-clearing equilibrium price.

### 3. Revenue-per-customer cap model

This model starts by setting prices using the same approach as the price cap model. A periodic adjustment is then made to reflect changes in usage per customer**.** The revenue cap includes all the adjustments for inflation and productivity included in a price cap model and adds an additional adjustment for changes in revenues per customer. The usage-per-customer adjustment is designed to decouple sales from revenue. The revenue adjustment is included to address the fourth concern about the cost-of-service model (i.e., linkage between sales and income that can act as a disincentive towards demand-side programs), which is also not addressed by the price cap model.

The general formula for a revenue cap model is:

$$RPC_{Year1} = RPC_{Year0} * (1+(i-x)) +/- z$$

where RPC is revenue per customer, i is a measure of inflation, x is a productivity adjustment, and z refers to items that are excluded from the rest of the calculation. The only algebraic difference between the price cap and the revenue cap is that one is adjusting price and the other is adjusting revenue per customer.

### 4. The three regulatory models: Summary of effects

The success of any regulatory measure depends on details, but some generalizations can help understand the incentive landscape. The table on the next page attempts to display those generalizations.

**Table 1: Basic Regulatory Structures in Context with Goals**

| Goals | Cost of Service | Price Cap | Revenue Cap |
|---|---|---|---|
| **Short-term cost effectiveness (operational management)** | Incentives limited due to frequent take-backs at rate case and capped profits. | Increased incentives to minimize costs as give-backs are reduced and profits are not being capped. | Increased incentives to minimize costs as give-backs are reduced and profits are not being capped. |
| **Long-term cost effectiveness (infrastructure decisions)** | Bias towards long-term large projects that can be timed with rate cases. If reward not perceived to compensate for risk, management may not invest sufficiently. | Capital bias eliminated. | Capital bias eliminated. |
| **Demand-side Management** | Coupling of sales and income may make utility management adverse to programs that reduce sales. | Coupling of sales and income may make utility management adverse to programs that reduce sales. | Sales and revenue are decoupled. |
| **Climate Change** | No particular incentive unless mandated. | No particular incentive unless mandated. | No particular incentive unless mandated. |
| **Quality of Service** | Quality-of-service targets usually not explicitly provided, but may be used. Normally relies on "bonus" ROE. | Quality-of-service incentives usually explicitly included. | Quality-of-service incentives usually explicitly included. |
| **Innovation** | Benefits of innovation quickly passed onto customers. | Benefits of innovation retained by utility until next cost review. Flexible pricing allows for product flexibility. | Benefits of innovation retained by utility until next cost review. Flexible pricing allows for product flexibility. |

### B. Adjustments to the core regulatory models

Each of the foregoing three models can work in conjunction with one or more types of adjustment. The main examples are described next.

#### 1. Adjustment clauses

Utilities sought, and regulators approved, this concept in the 1970s in response to rising fuel prices. The purpose was not "incentive," but profit stability between rate cases in light of rising costs. Some fuel adjustment clauses, because they focused on the cost of energy and not the price of fuel, created an implicit disincentive to power plant productivity and line loss reduction. Today, some commissions have modified the concept to include explicit performance incentives addressing availability of base-load generating units.

Adjustment clauses are not limited to fuel costs.

#### 2. Recovery of costs associated with mandated projects or efforts

Mandates, as distinct from incentives, are a way of directly changing a utility's behavior according to explicit regulatory or legislative expectations. Some adjustment clauses are designed to recover the costs associated with government mandates as diverse as tax change, environmental rules, low-income energy assistance programs, and requirements to build a particular distribution line or increase the use of renewable resources. These recovery clauses are not incentives, but rather recognitions of the regulatory responsibility to allow recovery of mandated costs.

### C. Concepts relevant to the effectiveness of regulatory inducements

#### 1. Regulatory lag

Each of the three core concepts discussed above relies on regulatory lag to encourage utilities to reduce cost. The premise is that after there is a base determination in a rate case, utility management can increase its income by reducing its cost. The price and revenue cap models try to increase the cost minimization incentive, relative to the cost-of-service model, by prolonging the period rate cases and eliminating the profit cap.

#### 2. Allocation of benefits between shareholders and ratepayers

There is inherent tension between the utility's obligation to minimize ratepayer cost and the human reality that regardless of legal obligation, not every manager will do so if there is no reward to her company. Recognizing this tension, some commissions allow the utility to retain some portion of the cost reductions achieved through an incentive program, a tactic sometimes called a "sharing" of benefits. The arguments go both ways. Ratepayers express concern that if they do not receive the full benefits of cost reduction, then utilities are shirking their obligation to minimize ratepayer cost. Shareholders and management express concern that requiring ratepayers to share in cost reductions dilutes their incentive to manage efficiently.

### 3. Tradeoffs and secondary effects

Public interest goals are not entirely mutually consistent and often act as constraints upon another goal. Quality of service and reducing short-term costs can conflict. Mitigating climate change and reducing long-term cost strategies can conflict.[1] Incentives also can have unintended consequences. Pass-through mechanisms designed to allow a utility to recover costs associated with a mandate can reduce management's attention to cost minimization if they perceive cost recovery to be guaranteed without prudence review.

Regulatory mechanisms can also shift risk and change the purpose of certain management tools. A utility without a fuel clause may use energy cost hedging to protect a certain level of profits, while a utility that uses a fuel clause may use a similar hedge to ensure a certain level of price predictability for its customers. The fuel pass-through mechanism has the secondary effect of changing hedging from a profit stabilization tool to a price stabilization tool and raises the question of whether utilities or customers should pay the premium for the hedge.

### 4. Information asymmetry and gaming

#### a. Asymmetry of information

It is no secret that utility officials know more about their companies than regulatory officials. This asymmetry of information affects every relevant knowledge category: costs (capital and expense; historic, present and future); operations (e.g., the capacity and availability of plants); customer consumption patterns; financing opportunities; utility staff capabilities; opportunities for cost reductions; and technological potential; to name a few categories. If a utility's obligation (in return for receiving the exclusive right to serve) is to provide the essential services with excellence at reasonable cost, the regulator has her obligations: (a) to hold the utility to its obligation, by establishing and enforcing performance standards; and (b) to compensate the utility fairly—by setting rates that bear a reasonable relationship to prudent cost. Carrying out this regulatory obligation in the context of information asymmetry is a difficult task. If the regulator sets performance standards too low or rates too high, the ratepayers—who lack competitive alternatives—overpay for subpar service. If the regulator sets performance standards too high or rates too low, the company weakens from the strain of high expectations and insufficient compensation.

The regulator's dependency on the utility's information—timely, accurate, objective information—thus causes vulnerability for regulators, consumers, and shareholders. Eliminating this asymmetry is in everyone's interest. In assessing alternative regulatory measures, therefore,

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[1] For a discussion of ways that regulators can identify and weigh conflicting tradeoffs, see the last chapter of Ken Costello's *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

one criterion is the effect of information asymmetry.  A regulator cannot select a measure whose effectiveness requires data, if the regulator cannot get the data.

#### b. Gaming

Gaming is related to information asymmetry.  The term "gaming" has a negative connotation—a hint of underhandedness, if not unlawfulness.  Such behavior is always possible when there is opportunity and incentive, such as when the gamer has more information than the regulator, and when the gain exceeds the probability of detection times the penalty from detection.  But gaming also includes the lawful exploitation of loopholes in regulatory design. Here information asymmetry again is relevant, because it can cause the regulator to overcompensate a utility or underestimate performance potential.  The prudent regulator asks: "If I were the utility, how would I respond to this program in light of my obligation to maximize profits?"

## III. Goals and incentives

Having described the major models and the types of adjustments, we turn now to the six goals identified in the Overview.  For each goal, we list the relevant devices available to regulators, assessing the strengths and weaknesses of each.

### A. Cost-effective infrastructure investments subject to policy constraints

#### 1. Traditional models

The cost-of-service model provides a utility an opportunity to earn a reasonable return on its rate base.  Increasing either rate base or authorized return, all else being equal, increases profitability.  This link between rate base and profitability creates a tendency towards capital expenditures (other factors being equal), and against expenses.  On the other hand, a utility will underinvest if the risk associated with the investment is not commensurate with the authorized return.  For these reasons, it is possible for a utility to resolve the “buy vs. build” comparison suboptimally.

To encourage capital investment, some states (e.g., Iowa and Nevada) have modified the cost-of-service model to include a bonus rate of return for certain facilities or projects.  Virginia provides rate-of-return bonuses for the entire rate base if the utility meets certain goals, including adding certain technologies to the utility’s fuel mix.

#### 2. Pre-approval and securitization

There are many levels of pre-approval.  A regulator can pre-approve a project, i.e., determine that the selection of that project was a prudent decision, without guaranteeing recovery of a particular cost level.  Alternatively, the regulator could approve a project at a particular cost level, or review and authorize cost recovery periodically, as the costs are incurred.  Guaranteed cost recovery mechanisms are sometimes restricted to mandated projects (e.g., the state mandates that a utility build a base load coal facility). When cost recovery is guaranteed, regulators if so authorized should consider having the project financed in whole or chiefly by securitized debt to reduce the total cost of a project where little cost-effectiveness discretion exists.

The effectiveness of pre-approval in achieving a commission's objectives depends on the relationship between risk and reward. For example, in a given context, is pre-approval necessary to attract investment dollars at reasonable cost, or does it merely shift risk to customers with no gain in efficiency? Is there explicit recognition of risk-shifting in the authorized return on equity? Is there reason to grant pre-approval to one project but not all others?

States that have a pre-approval process include Iowa, Nevada, Ohio, Virginia and Wisconsin.

### 3. Cash flow enhancement

Another way to reduce a utility's risks associated with capital investment is to enhance cash flow. This option comes in several forms.

#### a. Recovery of construction work in progress

In the traditional model, a utility could not recover, and earn return on, its capital investment until the investment was commercially operational (a status sometimes referred to as "used and useful"). Some jurisdictions allow *construction work in progress* (CWIP[2]) in rate base for all or some projects (e.g., mandated projects). The inclusion of CWIP in rate base accelerates cost recovery and decreases the risk associated with capital investments.

Because CWIP allocates costs to customers prior to the project's operation, the cost-payers differ from the benefit-recipients. And, depending on the internal discount rates used, the inclusion of CWIP and the cessation of AFUDC can reduce or increase the present value cost of the project.

States that allow CWIP in rate base include Alabama, Kentucky, Mississippi, Minnesota, New York, Tennessee, and Virginia.

#### b. Future test year

Another way of accelerating the cash flow associated with a project is to use a future test year. A future test year allows projects to be considered for inclusion in rate base earlier than historic test years. This early inclusion in rates occurs because under a future test year a

[2] Accounting tutorial: When CWIP is allowed in rate base, the utility stops booking a non-cash source of income called *allowance for funds used during construction* (AFUDC). AFUDC is capitalized during the construction phase and becomes a cost of the project, just like concrete and steel, when the plant is placed into service.

regulator is permitted to look at events (such as the imminent completion of a plant) that are about to occur rather than just those that have already occurred

#### c. Accelerated depreciation

Straight-line depreciation is the traditional way of recovering the cost of a project. Under straight-line depreciation, the cost of the investment is recovered through rates in equal annual installments over the projected useful life of the investment. Accelerated depreciation front-loads the recovery depreciation expense. This front-loaded cost recovery reduces the utility's cost recovery risk. Accelerated depreciation causes ratepayers who purchase in the plant's early years to bear more depreciation expenses than ratepayers who purchase in the plant's later years.

### 4. Mandated investments and system benefit charges

The introduction to this document discussed the distinction between encouragement and mandate. Encouragement involves "incentive" payments or penalties; mandates require only cost recovery—although rewards and penalties relating to the utility's efficiency in meeting the mandate deserve consideration. States have mandated utility actions on Renewable Portfolio Standards (over twenty states), base load stations (Wisconsin and Iowa), and advanced metering (California).

System (or societal) benefit charges (SBC) can fund mandated programs, such as green power, generation using a particular technology, low-income energy affordability, or energy efficiency. States with SBCs include: Arizona, California, Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Oregon, Rhode Island, Vermont, Washington, and Wisconsin.

By definition, a specific mandate removes utility discretion. Take the problem of future carbon regulation. The utility's general regulatory obligation is to supply necessary power at the lowest reasonable cost. That obligation can have multiple solutions that change as cost factors change. A specific renewables mandate introduces a permanent cost change that reduces discretion to adopt other measures. This statement does not imply author opposition to renewable mandates; indeed, such mandates have legitimate purposes other than mere cost minimization. The point is that mandates and encouragement differ in their flexibility. Mandates are more permanent than encouragements, which the regulator can calibrate to circumstances.

### 5. Ownership

To ensure sufficient generation to meet its load, the utility can build and operate a generating station or it can purchase power from others. The same options exist for demand-side resources. The attractiveness of ownership relative to purchase is well-known. Ownership brings rate base and the associated return on equity. The utility's incentive to operate plants efficiently and to exercise prudence in plant additions and repowerings depends on the ease with which regulators allow cost recovery.

Purchase power is not without its difficulties. A third-party producer's incentive to seek cost-effectiveness depends on its contract terms, which can range from fixed rate to cost-sharing to full cost pass-through.

The foregoing statements should produce caution in assuming or inferring that a utility favors build over buy. Facts matter, and even within a particular utility there can be different preferences at different times.

The Oregon Public Utility Commission approved an investigation into the build vs. buy question in 2006 under Docket #UM1066. A staff report describes the following impediments to removing a utility's assumed preference for building:

1. Credit rating agencies have been imputing debt equivalency to some long-term purchase power contracts, changing the utility's capital structure.

2. Utilities are concerned about the ability of the seller to meet its obligations over many years.

3. Utilities are biased to building to increase their income potential.

4. Utilities may want to "empire build" rather than minimize costs.

Potential strategies to address these concerns include:

1. Expedited review and allowance of cost recovery of purchased power costs.

2. Equity offsets to deal with the imputed debt issue.

3. Timely recovery of purchased power costs through a purchased power cost mechanism.

4. Inclusion of purchased power costs in rate base.

5. Hedging incentives (such as those used in New York for Con Edison).

6. Price cap regulation.

Another response, where the utility is concerned with the long-term reliability of the seller, is to allow the utility to purchase through an affiliate (although the classic problems of affiliate relations apply here). Wisconsin, for example, by statute allows a utility to build a plant through an affiliate and buy the output under the terms of long-term power contract approved by the commission. Advance commission approval of long-term power contracts, accompanied by securitization of a ratepayer revenue stream to cover the purchase costs, can support asset-back financing that can reduce the projects financing cost[3].

### 6. Small, short-duration projects

Examples of small projects with short durations are improvements to existing transmission and distribution infrastructure. Under cost-of-service regulation, it is the major projects which influence a utility's decision to file a general rate case. This approach allows the utility to start earning a return on its capital investment contemporaneously with the project's commercial operation. A utility does not file for a rate increase with every small capital project, yet such small projects can equal one large project in dollar terms. A small project to repair an aging section of gas line may take a couple of days. It might not enter rate base for years. The result is a potential discouragement of small yet important projects.

One solution is to treat these costs as "recurring maintenance expenses" in the next rate case. Another approach is to allow recovery through an adjustment clause. All of the above approaches reduce a utility's risk associated with these small, short duration projects. Expensing these costs in a rate case is the administratively easier approach, while tracking the costs through an adjustment mechanism ensures that the targeted work is performed before rate relief is granted.

FERC has allowed for automatic rate adjustments for transmission system upgrades. The Pennsylvania and Illinois Commissions have allowed water utilities to pass through the costs associated, including a return with distribution system improvements. The water programs have led to increases in the utilities' level of infrastructure investment.

## B. Cost-effective demand-side management and energy efficiency

### 1. Decoupling

In the traditionally regulated utility, a coupling between sales and profitability occurs when some of its fixed costs (including return on equity) are included in the variable components of a utilities standard two-part tariff. Lost profit occurs whenever a utility experiences sales reductions, whether the reason is milder-than-normal weather, a slow economy, energy efficiency encouraged by the utility, energy efficiency that occurs on its own, or the use of distributed resources not owned by the utility, such as small net-metered renewable resources.

A number of solutions to this problem exist. Note that in a separate paper submitted to the Commission, NRRI addresses the question of whether a commission should rely on the utility to provide or support DSM and energy efficiency programs. For the purposes of this section of the present paper, we will assume that there is such reliance.

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[3] See, e.g., D. Boonin, "Mitigating 'Mandated' Rate Hikes," *Public Utility Fortnightly*, May 2007.

### a. Decoupling trackers

This automatic adjustment clause increases or decreases rates as actual sales compare to base sales established in a rate case. The mechanics of this approach include setting base figures not only for each rate class but for each tariff component. If a utility has a tariff with time-differentiated rates and a demand charge and energy charge, decoupling is most accurate when an adjustment is applied to each component rather than based upon the total bill or energy usage. In implementing this type of a decoupling mechanism, it is important to adjust only for revenues associated with fixed costs (net revenues), not gross revenues. A decoupling tracker that allows the utility to recover variable costs (which were not incurred due to the sales reduction) would produce over-recovery. Decoupling trackers require recurring audits and a reconciliation mechanism.

California, Idaho, Maryland, and Oregon are among states with decoupling trackers.

### b. Lost revenue adjustment clauses

The lost revenue recovery adjustment (LRRA) creates an explicit revenue adjustment for particular actions taken by a utility. For example, if a utility replaces a light bulb with a compact fluorescent, the adjustment would recover an amount specifically associated with the revenues foregone from that action. The LRRA targets revenue reductions associated with utility energy efficiency efforts, not reductions associated with the economy, the weather, or non-utility-funded energy efficiency programs. It can be difficult to quantify either the action or the effect on revenues of softer yet important programs such as energy efficiency customer education sponsored by the utility. Even with tangible items like bulbs, there is uncertainty about whether they get and stay installed. Continuous measurement and monitoring is required to ensure that estimated savings are reasonable approximations of actual savings. Ohio, Indiana, Massachusetts, Oklahoma, and Vermont have used LRRA clauses.

### c. Rate structure

Regulators can eliminate the coupling of sales and income by shifting from the standard two-part tariff (that collects a portion of the utility's fixed costs and profits through the variable portion of the bill) to a straight-fixed variable tariff that is designed to recover only variable costs through variable charges. The straight-fixed variable approach, unlike other decoupling strategies, requires no tracking, auditing, extra hearings, or reconciliation adjustments. The straight-fixed variable rate design, because it lowers the variable charge, reduces a customer's incentive to conserve, which is in opposition to the climate change goal. An NRRI paper addressing this reduced incentive will issue in mid-July.

The straight-fixed variable rate structure is used for gas utilities in North Dakota, Georgia, Oklahoma, and Missouri.

#### d. Revenue caps

Revenue-per-customer caps work similarly to a decoupling tracker within a cost-of-service or price cap model. Rates are decreased when usage per customer increases and increased when usage per customer decreases. These adjustments are usually made less frequently than decoupling trackers, e.g., annually versus monthly, reducing administrative costs.

### 2. Capitalization of expenditures

If demand-side and energy efficiency expenditures are expensed whereas supply-side resources enter rate base, a profit-maximizing utility under the cost-of-service model will prefer the latter over the former, all else equal. Where a commission or legislature wishes to encourage utility involvement in energy efficiency programs, a commission could direct that energy efficiency costs be capitalized. This capitalization would treat demand- and supply-side resources comparably. Where energy efficiency investments are small and numerous, the small short-duration problem discussed at III.A.6 arises; the regulator can apply similar solutions.

### 3. Utility retention of cost reductions

A commission can allow a utility to retain a portion of the cost reductions associated with utility-sponsored energy efficiency or demand-side programs. As an incentive to efficiency, retention works better if applied as occurred rather than deferred to the next rate case, so that recovery is more certain and the utility does not lose the time value of money. Utility retention has the downside of dampening financial signals to the customer, who receive less of the rewards from their participation in programs.

### 4. Alternative providers of energy efficiency services

Energy efficiency service is not a natural monopoly. While some utility role is necessary given its access to customers and data, regulators should determine whether the best provider of a particular service is the incumbent utility or the competitive market. The separate paper by Nancy Brockway of NRRI addresses this question.

## C. Climate change

The six most frequently cited strategies for a utility to reduce carbon emissions are: increased generation from natural gas; improved end-use energy efficiency; increased generation from low-emission renewable resources such as solar, wind, and hydro; end-use fuel switching from electricity to natural gas; carbon sequestration; and increased nuclear generation. Another carbon mitigation strategy that may increase the carbon footprint of the utility but mitigate carbon emissions overall is electric plug-in vehicles.

### 1. State bonds

State legislatures could authorize tax-exempt pollution control bonds to fund any or all of the carbon reduction strategies. Note that the use of all debt (and no equity) to fund such investments removes the utility's opportunity to profit from them. Active regulatory involvement is necessary to ensure that utility decisions align with the commission's goals.

North Carolina, Pennsylvania, West Virginia, and Wisconsin are among the states that have issued tax-free bonds to finance utility pollution control expenses.

### 2. Adjustment clauses

The question here is whether a path for recovery compliance costs should occur outside of general rate cases. Some states allow recovery of pollution control costs through fuel cost recovery mechanisms or separate surcharges. Design issues include: what specific costs to allow in a surcharge, which compliance strategy costs should be recovered through this mechanism, whether to treat all strategies the same way (e.g., nuclear vs. energy efficiency), and which costs to treat as capital versus expensed costs.

Adjustment clauses (whether or not the expenditure is financed by state bonds) track actual costs used to comply with environmental mandates. They require administrative costs and regulatory attention as do other pass-through mechanisms. If a profit is part of the cost passed through the adjustment clause, there is a potential bias toward capital-intensive projects if the cost-of-service model is in use.

Alabama, Arkansas, Florida, Indiana, Kentucky, Minnesota, Mississippi, Missouri, Ohio, Virginia, West Virginia, and Wisconsin allow for environmental surcharges.

### 3. Decoupling and other incentives that make demand resources as attractive as supply resources from the utility's perspective

Energy efficiency is often not embraced by utilities because of the lost income associated with diminished sales and the lack of profits associated with energy efficiency programs. See the section on cost-effective demand-side resources and energy efficiency.

### 4. CWIP in rate base and accelerated depreciation

States have allowed CWIP and accelerated depreciation for utility investments in pollution control equipment such as scrubbers. Indiana has allowed CWIP in rate base for environmental compliance investments, as have many of the other states listed as allowing adjustment clauses to recover costs related to environmental compliance. The same issues regarding CWIP and accelerated depreciation that are discussed at section III.A.3 apply here.

### 5. Carbon credit accounting

Carbon credits will likely be part of any climate change legislation. Some utilities will continue to pollute, buying credits to cover their emissions; others will install equipment to overcomply and then sell the excess credits they amass. State decisions on how to treat these costs and revenues will affect the utilities' incentives. Decisions that pass through to ratepayers the costs and revenues associated with carbon credits reduce the utilities' incentive to meet the carbon requirements cost–effectively. Decisions that grant the utility revenues equaling the market value of a carbon credit for all carbon abated while granting the utility no compliance costs shift the risk of compliance to the utility. Under the second approach, utilities are encouraged to find the least-cost means of compliance. Under either approach, the customers bear the risk of varying carbon credit prices.

On this subject, see the NRRI report, "State Commission Electricity Regulation under a Federal Greenhouse Gas Cap-and-Trade Policy," Dr. Andrew G. Keeler, January 2008, (http://nrri.org/pubs/electricity/08-01.pdf).

#### 6. A "DSIC" for carbon abatement investments

Some carbon abatement measures consist of multiple small projects. As with other short-term projects discussed at section III.A.6, deferring cost recovery until the next rate case can discourage investment. In the water industry, a solution to the problem of numerous small projects is the Distribution System Infrastructure Clause (DSIC). States using this measure (e.g., Illinois and Pennsylvania*)* allow utilities periodically to submit to recover the costs associated with certain types of investments and, upon commission approval, start earning a return on and of the investment between rate cases. Eliminating the bias against the short-duration carbon abatement investments raises the same concerns as when this methodology is used to encourage other short-duration projects (see sections III.A.6 and III.B.2).

#### 7. Governmental mandates

The legislature can mandate certain carbon abatement strategies, including in part: higher building energy requirements, renewable portfolio standards, or the construction of a nuclear plant. Mandates ensure alignment of utility practices with legislative goals, but do not ensure that the total compliance strategy will be cost-effective. We discuss other issues related to mandates at section III.A.4.

### D. Cost-effective operations

#### 1. Cost-of-service model

The cost-of-service model's main influence on management effectiveness is that the revenue requirement can reflect only prudent costs. This effort at influence has strengths and weaknesses. The commission's ability to distinguish prudence from imprudence is constrained by asymmetry of information and expertise. On the other hand, regulatory lag allows the utility to retain the benefits of management improvements between rate cases. Customers then benefit at the next rate case, when alert regulators can reset the cost structure lower to reflect those improvements. But the utility's exposure to and anticipation of these regulatory reactions tends to reduce management incentives to improve efficiency.

One response is for regulators (sometimes at the command of legislation) to extend the period between rate cases (allowing utility retention of cost savings), while allowing recovery outside of rate cases, through adders, for fuel costs and specific investments, such as pollution control equipment.  Adders have the inconvenience of ongoing tracking, auditing, prudence review, and hearings thereon.  Adders specific to a particular activity can cause management to overemphasize that activity (especially if the adder includes a special return on equity benefit); and also can signal that prudence review is less likely than in a general rate case.

The cost-of-service model, absent adders, relies on an overall incentive rather than targeted incentives.  This broad incentive gives the utility discretion in where to cut costs, even if these cuts are not consistent with other goals.  A downside is that absent explicit incentives or requirements concerning quality of service, management has an incentive to trade off profit-through-cost-cutting against quality of service.  Finally, the return-on-equity calculation involves a "zone of reasonableness" that gives commissions discretion to reward and penalize utility efforts to satisfy a commission's performance standards, such as quality of service.  Actual earnings in excess of the authorized return can prompt commission investigations, leading toward rate reductions.  Since one reason for such high earnings could be management efficiency beyond that assumed in the prior rate case, this possibility of rate reductions can discourage management efficiency efforts.

### 2. Price caps

Price caps increase the incentive for cost-effectiveness by increasing the period between formal cost reviews.  To extend the period between rate cases, the price cap formula allows automatic adjustments through some type of an inflation index.  Choosing the appropriate inflation index can be challenging.  Traditional indexes such as the Consumer Price Index or Producers Price Index,[4] being general indices, will not reflect accurately the specific price-escalating experience of a given utility.  The price cap formula usually includes a productivity adjustment (lowering rates) based on the assumption that management should take cost-reducing actions, including actions to offset inflation.  As with all rate setting, there is risk that the adjustments for inflation and productivity can deviate from the optimal factors, producing profits lower or higher than the regulator intended.

As with the cost-of-service model, price caps encourage cost-cutting, but absent quality of service requirements and penalties there is risk of service quality reductions.  Price cap models, therefore, usually contain explicit quality of service targets and incentives.  The quality-of-service mechanisms range from outage standards to call response times.  See the quality of service discussion at section III.E below.

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[4] The Consumer Price Index is based upon a bundle of consumer goods.  The Producers Price Index measures the average change over time in the selling prices received by domestic producers for their output.  The PPI has subclasses for utility types (e.g. electric power distribution vs. electric power generation, transmission, and distribution).  The PPI is, therefore, a better adjustment for inflation of utility costs than the CPI.  Both are published by the Bureau of Labor Statistics.

The price cap approach (because it precludes the regulator from initiating rate reduction proceeding during the price cap period), creates the risk of excess, or insufficient, utility profits (in contrast to the cost-of-service model, which allows the regulator or the utility to initiate a new rate case if actual returns exceed authorized returns).

The price cap can also eliminate the bias towards overbuilding if rate base and rate of return are not implicitly used in setting the price cap.

Price caps share the cost-of-service model's potential to discourage demand-side management initiatives (i.e., the problem of profits being linked to sales) if the rate design recovers fixed costs through variable charges.

Asymmetry of information affects the regulator's ability to set the price cap accurately and to assess quality of service under the price cap. The utility knows, for example, the information on call response time, as well as its employees' capability in that area. Outage response also is a technical area in which the utility can assess better than commission staff its true capability. The problem works in two directions. Knowing the ease of improvement, a utility might seek low standards. On the other hand, the less a regulator knows, the more likely it imposes unreasonable demands or penalties on the company. Getting the metrics of the incentives assessed correctly is, therefore, important if regulators are to avoid constant reviews and hearings.

California, Kentucky, Maine, and Massachusetts are examples of states where price caps are used.

### 3. Revenue caps

Revenue caps work similarly to price caps from the perspective of operational cost effectiveness.

Florida has used a hybrid of the revenue cap model. New South Wales also uses a revenue cap.

### 4. Performance indices

Regulators can use performance indices as a basis for cost recovery or as a benchmark for rewards and penalties. These indices compare a utility's historical performance to that of other utilities. Indices also can assist in normalizing data. The commission can make the comparison and adjustment to a utility's prudent costs within a rate case or other prudence reviews, or through an adjustment clause setting and assessing a pre-established goal with an incentive attached. Targeted incentives can single out a particular problem area, but in doing so can cause overemphasis on the targeted elements.

### 5. Pass-through mechanisms

Regulators, either on their own or on legislative command, have allowed utilities to pass through certain costs on an as-incurred basis, rather than having to file a full rate case to justify these costs. In this pass-through context, the utility's incentive to operate efficiently depends on the extent of commission scrutiny of the costs. Some clauses are mere pass-throughs; others have rewards and penalties built in.

Further, if a mechanism contains an "incentive" not aligned with the regulator's goal, a suboptimal result should cause no surprise. An energy clause incentive that rewards power plant availability would induce a focus on availability, not heat rate, even if costs would drop more with an emphasis on improving heat rate.

Effective pass-through mechanisms follow these principles:

1. The dollars involved should be significant, such that without the adjustment there is a material effect on a utility's financial condition.
2. The cost recovery could not be fully resolved effectively in the last or next rate case.
3. Auditing is possible, so that dollars recovered match dollars incurred.

#### a. Energy clauses

Energy adjustment clauses present a special problem. Energy costs are the product of price times quantity. The customary purpose behind an energy clause is to recover cost increases associated with ***price*** increases: specifically, increases in the price of fuel and purchased power, where prices are hard to predict. An energy adjustment clause that recovers total energy ***cost*** increases recovers costs associated with both ***price*** and ***quantity*** increases.

This design can produce disincentives for utility operational efficiency, since the clause allows the utility to recover cost increases, whether those cost increases arise from (a) fuel price increases; (b) decreased power plant availability or efficiency (which requires purchase of replacement power, whose cost can flow through the clause); or (c) line losses. In contrast, if the clause permitted the pass-through only of cost increases associated with price increases, the utility would retain a strong incentive to keep power plants operational, heat rates reasonable, and line losses low. And if the utility were allowed to retain some profit from off-system sales, its incentive to operate its plants well would increases further.

The typical clause, however, dampens a utility's incentive to reduce quantity increases, such as total fuel use or total purchased power, since cost increases associated with increased quantities will flow through the clause rather than remain the utility's cost responsibility. These concerns call for careful design of the clause.

Some states have addressed the power plant productivity challenge by introducing incentives to encourage an increase in the availability of base load units. Examples are Florida, Kentucky, and Wisconsin.

Hedging is a strategy that utilities can use to make energy costs more predictable. Hedging is an insurance policy that comes at a premium cost. Some fuel clauses allow the pass-through of these premiums to customers. The purchase of a hedge is not consistent with a cost minimization goal. There is a tradeoff between cost minimization and cost certainty. Regulators who allow the costs of hedges in a fuel clause should give utilities clear policy guidelines on how much price uncertainty volatility it is willing to accept and at what cost. Hedges play a very different role when the utility recovers its fuel costs through base rates rather than a fuel clause. When the utility recovers fuel costs through base rates and not a fuel clause, hedges become a profit stabilization tool rather than an electric price stabilization tool.

Gas procurement incentive plans encourage a utility to purchase its gas supply more effectively by setting a cost benchmark, then sharing the difference between the actual results and the benchmark with consumers. Given the difficulty in setting a benchmark that reflects achievable, superior performance, regulators use bands of reasonableness (sometimes called collars or null zones), within which performance produces neither reward nor penalty. Benchmarks often rely on a combination of historical values and adjustments. As with most incentives, the utility's informational advantage concerning storage, transportation, and gas cost forecasts, among other areas, inhibits regulatory effectiveness. Commissions also need to decide about trade-offs between price volatility and price stability (plus a hedge premium). Ongoing scrutiny is necessary. States with gas procurement incentive mechanisms include: Illinois, Iowa, Kentucky, Minnesota, Missouri, Oregon, Tennessee, Washington, and Wisconsin.

#### b. Recovery of unexpected or extraordinary costs

Some commissions allow the recovery of unusual costs not anticipated at rate case time. Examples are legislative changes in tax rates or severe storm damage. Adders to allow cost recovery, provided the cost is known (or can be monitored and subjected to prudence review) are one solution and are operating-cost-neutral at best. There is a risk of revenue distortion, however, arising from this "single-issue ratemaking." The distortion can occur because in establishing a revenue requirement, the regulatory assumption is that although any particular actual cost will likely vary from the predicted cost, the highs and the lows will balance out. Singling out particular expenses (highs) for cost recovery can upset this balance.

#### c. Recovery of costs associated with mandates

Mandates can stem from a commission order or a statute. Build a particular plant. Upgrade a particular power line. Reduce carbon emissions. Eliminate winter shutoffs. Increase renewable resources. Where the regulator knows these costs (or can monitor them through prudence review), an adjustment clause allows full pass-through between rate cases. While auditing can ensure that dollars recovered match dollars incurred, the more difficult challenge is ensuring that the incurred costs are least cost.

#### d. Profit incentives embedded in pass-through mechanisms

Another type of adjustment clause is explicit profit-based income incentives that are recovered through rate changes between rate cases. One example, discussed above, is the change to base rates allowed through inflation and productivity adjustments under a price cap regime. Another example is a surcharge (or rate reduction) for quality-of-service achievements (or deficits). For capital projects, such as transmission lines, infrastructure improvements, and renewable resources, regulators and legislators have considered special profit adders, such as FERC's "incentives" order allowing higher returns on equity for certain transmission investments. Such concepts can target and induce particular actions, but they also can introduce a bias favoring capital projects over expensed items. As noted previously, special treatment of one cost influences management to favor that cost. A transmission cost recovery mechanism, for example, favors a transmission solution to a congestion problem over location-specific generation or location-specific demand management.

### E. Service quality

The goals of cost minimization and service quality can conflict. Improved reliability and customer response usually increase costs. The competitive market manages these tradeoffs because customers indicate a preference for either service or price. The market differentiates between variations of a particular service—for example, the selection of chauffeur services between a bus, taxicab, or a limousine. Competitive retail businesses make decisions about return and credit policies, store hours, and the frequency with which rest room are cleaned, all to influence market share and profitability.

Without the guidance of competition, utility regulators must themselves establish implicit or explicit service quality standards for utilities. These standards fall into two general categories: (1) those generalized with an implicit reward or penalty, and (2) those offering a specific reward for specific goals. An example of a generalized incentive is when a regulator varies the utility's authorized return on equity based on service quality.

The specific rewards can target such factors as frequency of customer complaints, telephone response time, electric service interruptions, lost work time (safety measure), billing adjustments, and service appointments met. Power quality rules are usually mandated within the service requirement of a utilities tariff.

Regulators must establish effective benchmarks and financial incentives to make these types of programs worthwhile. See Kentucky and Massachusetts, for examples. An example of Massachusetts' service quality parameters for Massachusetts Electric Company is provided on the next page:

**Table 2: Sample of Quality of Service Performance Measures**

| Performance Measure | Weight | Penalty or Offset |
|---|---|---|
| **Frequency of outages** | 22.5% | $3.0 M |
| **Duration of outages** | 22.5% | $3.0 M |
| **On-cycle meter reads** | 10% | $1.3 M |
| **Timely call answering** | 10% | $1.7 M |
| **Service appointment met** | 10% | $1.7 M |
| **Complaints to regulators** | 5% | $0.7 M |
| **Billing adjustments** | 5% | $0.7 M |
| **Lost work time accidents** | 10% | $1.3 M |

Explicit quality-of-service benchmarks necessarily focus management's attention on the benchmarked item and away from other issues and strategies, even if those other issues and strategies are more cost-effective. Creating tariffs that encourage different levels of service for a broad base of customers is new to utilities. Interruptible and time-of-use options are a start. Regulators can allow utility tariffs that provide different service levels and savings, ranging from automatic bill payments to pre-paid bills, paperless bills, and a myriad of other customer service components that are now mandated and uniform for all customers.

### F. Innovation

Competitive markets drive innovation as a means of both survival and profit maximization. In regulated monopoly markets, regulatory attention is necessary.

A general mandate coupled with prudence review is one approach. Mandating a particular percentage of renewable energy but not specifying the method (e.g. owning vs. buying) can spur investments that can create both innovation and economies of scale. Specific incentives, such as those associated with speedier responses to customers, can encourage a utility to invest in new telecommunication systems and employee training.

Some elements of the traditional cost-of-service model conflict with the goal of innovation. Innovation involves upfront costs that may produce no benefits. Assigning shareholders the costs and customers the benefits does not stimulate utility action. The price cap model is more innovation-friendly, since it involves longer lags between rate cases, and thus more opportunities for the utility to retain benefits. A pure price cap approach, which ignores costs, creates a superior environment for innovation, as there are no explicit "take-backs" for cost-effectiveness.

Legislators and possibly regulators can also establish funds to promote innovation (see the discussion on System Benefit Charges at section III.A.4). Questions then arise as to who allocates these funds, and to what purposes.[5]

The ratemaking treatment of research and development expenses can also affect innovation. Decisions of whether, when, and how quickly to allow cost recovery matter. Decisions on whether to allow the utility to retain revenues from third-party sales facilitated by the new technologies also matter. Regulatory insistence on successful projects will cause management to emphasize safe, known projects rather than more risky but potentially groundbreaking projects. Timing of cost recovery is relevant also. Regulators can also choose to allow a utility to implement new services (e.g., a plug-in electric car tariff) between rate cases, and recover costs in the next rate case, if the utility demonstrates benefits.

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[5] See, e.g., the California Public Utilities Commission's order creating the California Institute for Climate Solutions (CICS). *Opinion Establishing California Institute For Climate Solutions*, Decision 08-04-039 as modified by Decision 08-04-054 (April 24, 2008). Available at http://docs.cpuc.ca.gov/published/FINAL_DECISION/81946.htm. A ratepayer surcharge of $60 million per year, for ten years, will create the initial funding. The Commission's order requires that the CICS find additional funding. CICS will have three priorities (slip op. at 4):

1. To administer grants for mission-oriented, applied, and directed research that results in practical technological solutions and supports development of policies likely to reduce GHG emissions or help California's electricity and natural gas sectors adapt to the impacts of climate change.
2. To speed the transfer, deployment, and commercialization of technologies that have the potential to reduce GHG emissions or otherwise mitigate the impacts of climate change in California.
3. To facilitate coordination and cooperation among relevant institutions, including private, state, and federal entities, in order to most efficiently achieve mission-oriented, applied and directed research.

Some parties have raised questions about the Commission's legal authority to issue the order, which is subject to rehearing as of this writing.

Regulators can also encourage innovation by approving the costs associated with pooled research efforts such as EPRI, GRI, and NRRI. Utilities in states with pre-approval authority can ask for the pre-approval of prototype projects or investments in a particular research and development project.[6]

[6] On the subject of demonstration projects, see S. Hempling, "Joint Demonstration Projects: Options for Regulatory Treatment," *The Electricity Journal* (forthcoming Summer 2008).

# Appendix

## Mathematical overview of the three models

Paul Joskow[7] provides a comparison of a cost-of-service model to a price cap model in simple mathematical terms. The basic formula used by Joskow is:

R = a + (1-b)*C, where

R = allowed revenues

a = fixed component

C = the utility's realized costs, and

b = sharing parameter that defines how closely costs and revenues are linked.

Under a cost of service model, "a" and "b" each equal zero. Revenues are entirely determined by costs.

Under a price cap model, "a" equals the regulator's assessment of efficient costs; "b" equals 1; thereby eliminating the importance of actual costs. If at the starting point "a" (assessment of efficient costs) and "C" (actual "reasonable" costs) are the same, so will be the revenue requirement under either model. The difference in the frequency of cost review or regulatory lag is what makes the cost-effectiveness signals different between these two models.

The revenue cap (not modeled by Joskow) could be presented in a similar format with "R" being revenue per customer rather than total revenue. Changing R from allowed revenues to allowed revenues per customer provides for adjustments based upon usage per customer but does not change the other relationships.

It is not necessary to have a single model for all costs or for any model to use only 1 or 0 as values of "a" and "b." The ability to set different values of "a" and "b" for different goals or incentives presents infinite opportunities to design different incentives depending on the need. By setting the value of "a" and "b" each at zero for fuel costs, the cost recovery is through a cost-of service model. If "a" were set at some targeted dollar amount for transmission maintenance and there were an outage-based incentive and "b" were set equal to one, transmission operations would be handled under a price cap. When "b" is set at something between 0 and 1, a hybrid is created, such as a fuel pass-through mechanism with a power plant performance incentive.

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[7] *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks*, Paul L. Joskow, MIT, January 21, 2006 (revised). Prepared for the National Bureau of Economic Research Conference on Economic Regulation.

## Suggested Reading

*Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks*, Paul Joskow, MIT, January 2006.

*Electricity and Gas Utility Performance-Based Ratemaking Incentives*, California Public Service Commission Staff, September 2000.

*Incentive Regulation for Electric Utilities*, Florida Public Service Commission Staff, Tallahassee, FL, December 2006.

*Critical Issues in the Regulation of Electric Utilities in Wisconsin*, Wisconsin Policy Research Institute Report, April 2006.

*Performance-Based Ratemaking for the Elimination of the Build-vs.-Buy Bias*, Oregon Public Utility Commission Staff, June 2006.