

Incentive Regulation—Design Key Plan Components I

Presented to:
AUC PBR Workshop

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May 26th–27th 2010

Agenda

Overview of Key Plan Components for Price Cap PBR

- ◆ Plan Coverage
- ◆ The Price Trajectory
 - Alternative Methods for Establishing a Price Path
 - Inflation Index and X factor
 - Treatment of Capital Expenditures
 - Exogenous Z factors
- ◆ Plan Term – Start and Termination Conditions and Off-ramps
- ◆ Benefit Sharing
- ◆ Service Quality

Key Trade-offs in Choosing Plan Components

Where to start?

- ◆ Difficult to talk about the specifics of PBR plan components without having clear objectives in mind for why transition from CoS to PBR
 - For the regulator:
 - Concern that incentives for efficiency (e.g. cost-reduction) are not strong enough
 - Perception that utilities exploit an information advantage
 - Administrative burden of annual rate cases is high
 - For the utility:
 - Cost pressures raise concerns about regulatory risk under CoS
 - Little reward for efficiency efforts, particularly those with long lead times and high capital requirements; may be able to exceed allowed ROE under PBR without taking on much risk
 - Regulatory costs are high with annual filings
 - For customers:
 - COS rate increases perceived as excessive, but costly to challenge
 - Want more rate stability and predictability than COS provides

- ◆ *The choice of (and trade-offs between) particular PBR plan components should be influenced by which of the above objectives are collectively paramount*

Plan Coverage

- ◆ Bundled versus unbundled services
 - For purposes of this discussion we will assume that we are talking about “base rates,” i.e., rates for the underlying pipes or wire distribution services
 - Gas and/or power procurement incentive plans are separate and distinct
- ◆ Plan coverage should make economic/operational business sense
 - [hypothesis] Gas and electricity distribution, gas transmission and electricity transmission are each different businesses subject to different costs, demands, market risks and capital requirements
- ◆ But coverage level should not be so restrictive as to limit operational and marketing flexibility
 - Probably not useful to create a PBR plan for residential electricity distribution service as distinct from, say, industrial service

The Price Trajectory

- ◆ Central idea of price cap regulation is to set future rates that create incentives for productive and allocative efficiency while reducing regulatory costs
 - *Productive efficiency*: Meeting customer demands at least cost
 - *Allocative efficiency*: Providing the highest value range of outputs/services to customers given least-cost mix of current inputs and future cost structure and technology (this was a driving force in telecom PBR)
- ◆ In energy distribution, may be more meaningful to refer to a price *trajectory* and not a price *cap* (since most utilities would not typically be using the flexibility to price different services below the cap)

Price Trajectory

- ◆ Basic form of price trajectory

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

Where:

P_t = price in current year t

P_{t-1} = price in prior year t-1

I = inflation factor

X = productivity factor

- ◆ A rate freeze policy, sometimes employed in the US, is a flat price trajectory, i.e., $I = X$

Other Forms of Control

- ◆ Can also define caps in terms of revenue growth, or revenues per customer growth
- ◆ With a revenue growth trajectory, will need to include some form of output growth factor or forecast in order to not create a disincentive to serve growing demand

Cost Forecast PBR Price Trajectory

- ◆ The “cost forecast” approach to defining I - X has been used in the UK
 - Rate cases are heard in periodic intervals (e.g., 5 yrs)
 - Total cost forecasts are developed for that forward period based on the “building blocks” of O&M, capital expenditure (Capex), depreciation, return and taxes
 - Rate base (RAV) is adjusted for inflation, and *real* rate of return is applied
 - A general economy-wide measure of inflation is chosen for I (hence the term “RPI – X” after the British Retail Price Index)
 - X is “solved for” such that the net present value of revenues produced by the RPI trajectory equals the net present value of total costs over the plan period, given a starting price
- ◆ This approach has conceptual similarities to the “forward test year” approach to cost of service regulation, but with explicit, pre-determined regulatory lag

Productivity Approaches to the Price Trajectory

- ◆ The Total Factor Productivity (TFP) approach to defining $I - X$ is based on the notion that the utility should be able to improve its productivity in the future at the same rate as its industry's productivity improvement in the recent past (where TFP is defined as output per unit of input)
- ◆ Thus, in its simplest form, the inflation index I is a measure of the expected total cost inflation of the relevant industry, and X is the expected industry productivity improvement (based on historical performance)

Mixed or Hybrid Approaches to the Price Trajectory

- ◆ One could “mix and match.” For example, suppose you thought that future O&M productivity might track historical industry trends, but that Capex requirements might look very different for different utilities
 - Apply historical productivity approach to O&M (sometimes called Partial Factor Productivity or PFP)
 - But employ an individual firm Capex forecast
- ◆ Have to be careful with hybrid schemes to not create factor bias incentives (e.g., incentives to inefficiently substitute capital for O&M)
- ◆ May be desirable if there are unique capital requirements that may require targeted treatment (e.g. “smart grid” technology deployment or mains replacement)

The “Menu-based” Approach to Price Trajectory

- ◆ Utility is given a choice of different future price paths, where each includes a partial “true-up” mechanism
 - A utility that chooses a high price path will expect to receive smaller rewards for cost reductions (in the form of a more complete true-up between price-path revenues and actual costs)
 - A utility that chooses a low price path will have a smaller true-up, and thus keep larger rewards for cost reductions
 - Traditional cost of service rates could be one choice
- ◆ Idea is that if utility expects to be able to reduce its costs quickly under the program, it will make higher profits by choosing the low price path
- ◆ If the menu is constructed properly, it will induce the utility to reveal its true expectations about future costs
 - Customers will be protected because prices will never be higher than under traditional cost of service
 - Utility will be protected from price trajectories that are too oppressive

The Inflation Index under TFP

- ◆ There are (at least) three possibilities that typically arise:
 1. Economy-wide measures of *output* price inflation (e.g., CPI or PPI)
 2. Industry-specific *input* price inflation
 3. Industry-specific *output* price inflation
- ◆ The ready-availability and simplicity of these types of inflation indices decreases from 1 to 3 above
- ◆ Each of these alternatives requires a different form of X, and the complexity of X-factor determination decreases from 1 to 3 above

Economy-wide Output Price Inflation

- ◆ A general inflation index that covers the entire economy or broad sectors of the economy
- ◆ Examples:
 - GDP-PI (Gross Domestic Product Price Index)
 - CPI and PPI (Consumer and Producer Price Indices)
- ◆ Advantages:
 - Well-maintained by agencies such as Statistics Canada
 - Simple to apply
- ◆ Disadvantages:
 - May not be a good proxy for utility industry (heavy commodity weighting and thus volatile?)
 - Adds complexity to X factor determination since must adjust X for
 - (1) input price differential between industry and economy, and
 - (2) productivity differential between industry and economy

Industry-specific Input Price Inflation

- ◆ Inflation measure that directly relates to the inputs (e.g., labor, materials and capital) used by the utility industry
- ◆ Likely not a published index, so is usually “constructed” from separate input price indices for labor, materials and capital
- ◆ Example:
 - In Enmax, AUC approved use of a weighted average of the Canadian Electric Utility Construction Price Index (EUCPI) and the Alberta Average Hourly Earnings (AHE) – both maintained by Stats Canada
 - AUC selected weights of 50% for each based on observed capital to expense ratios in the industry over an 11 year period

Industry-specific Input Price Inflation (continued)

◆ Advantages:

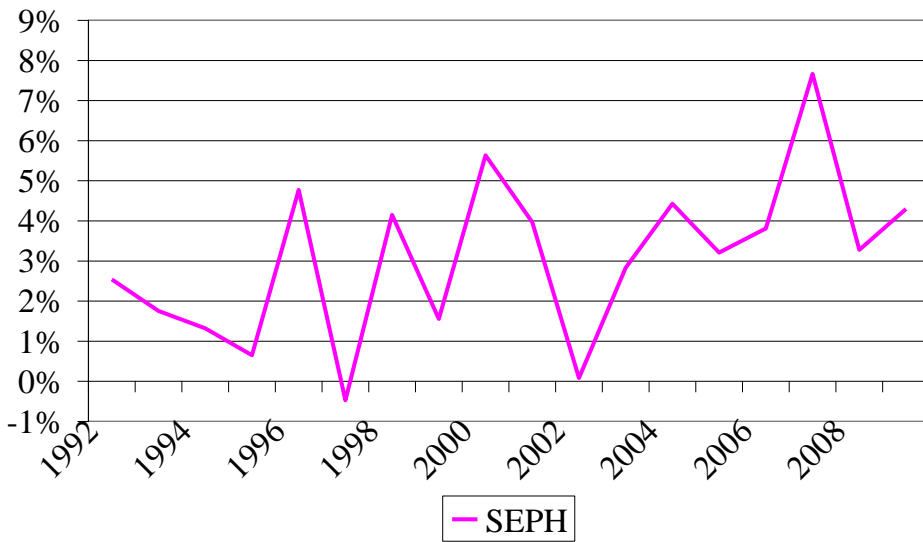
- Presumed to better track the industry
- Eliminates the need to calculate economy vs. industry input price and productivity differentials – X is “simply” the industry productivity trend

◆ Disadvantages:

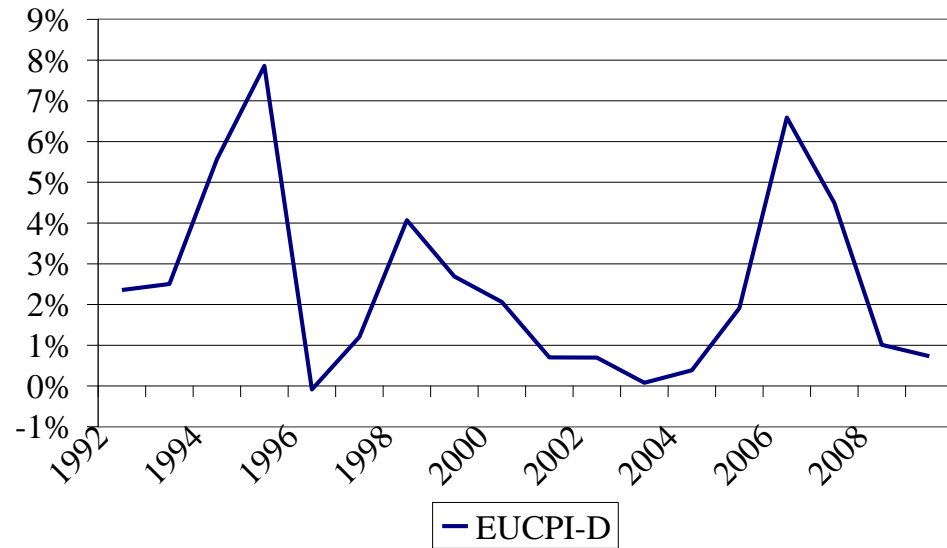
- Can become complex
- Weights can be controversial, particularly for capital costs
- Not clear that capital cost index is meaningful if investment requirements differ across firms in the industry
- If very regional in nature, may be influenced by the utility’s own behavior
- May be quite volatile if too specific

ENMAX Inflation Indices

SEPH



EUCPI-D



Industry benchmark output price inflation

- ◆ If one had a sample of comparable utilities (and not including the utilities in question), one could construct a benchmark inflation index from the output prices charged by these firms
- ◆ No need for X in this case, as output prices already reflect industry productivity trends
- ◆ Advantages:
 - Potentially simple
- ◆ Disadvantages:
 - Sufficient data unlikely to be available
 - Selection of sample and statistical normalization will be controversial (e.g., how to control for differences across firms)

X-factor Determination Under TFP

◆ Principles:

- Based on data that *immutable* to the behavior of the regulated firm and regulator
- Based on data representing *comparable* firms
- Based on data reflecting *stable* firm performance

◆ Methods:

- Indexing
- Econometric
- Data Envelope Analysis (DEA)

Issues in Empirical Methods for X Determination

- ◆ Indexing is the simplest and least data-intensive approach, but presumes that the sample data meet all three principles with little ability to test rigorously
 - Both the econometric and DEA approaches are designed to provide statistical estimates of *comparability*
- ◆ Econometric approach requires substantial data set from which an industry cost function can be estimated; model results are often very sensitive to specification
- ◆ DEA can also be controversial, in that it assumes that distance of firm from the frontier is due to inefficiency and not unexplained variance or outlier effects

Treatment of Capital Expenditures

- ◆ Capital costs (and associated return and taxes) are a large component of the costs of energy utility services (50% or more)
- ◆ Unlike O&M costs, capital costs are largely “sunk” and future Capex (outside of maintenance capital) tends to be lumpy, including additions and retirements
- ◆ These features create challenges for PBR mechanisms that include capital cost components, and (I-X) determinations based on observed price indices and historical TFP measurement
- ◆ Cost accounting approaches to capital recovery (straight-line depreciation on historical costs) do not necessarily capture the current *economic* or opportunity cost of capital
- ◆ Not correct to simply apply (I-X) to prices based on nominal cost of capital and depreciated original cost rate base that is not adjusted for inflation

Treatment of Capital Expenditures (continued)

- ◆ If it is likely that future Capex (over the plan period) will be different than past Capex (for individual utility or industry as a whole), it may be desirable to treat future Capex under an incentive mechanism that is separate from the price cap trajectory
 - In Enmax, transmission (as distinct from distribution) Capex is not covered by the PBR plan and is instead passed-through. New Capex is subject to prudence review
 - Alternatively, one could create a separate mechanism (such as a menu approach) that would reward the utility for revealing its best expected Capex forecast and then beating the estimate

Exogenous “Z” Factors

- ◆ Z factors are adjustments to the price cap trajectory that reflect uncontrollable cost pressures that are not reflected in I or X
- ◆ Examples:
 - Changes in government tax rates or regulatory compliance costs
 - One time transition costs due to restructuring or unbundling
- ◆ Formula becomes:
$$P_t = P_{t-1} * (1 + (I - X) - Z)$$
- ◆ Usual to describe eligibility criteria for Z-factor treatment as in Ontario IRM and Enmax (materiality, uncontrollability or causation, lack of impact on the inflation factor, and prudence)

“Z” Factors

- ◆ Can differ year-to-year during the plan
- ◆ But Z factors that are associated with specific and well-defined items are better -- the more “general” the ability to define Z-factor exceptions, the more detrimental they may be to efficiency incentives

Plan Term

- ◆ The issue of plan term interacts with other plan provisions in terms of its effects on incentives
 - The longer the plan term, all else equal, the greater the incentives for efficiency and cost-reductions, particularly for actions taken early in the plan term
 - If rebasing is built into the end of plan term, incentives will be attenuated as all future benefits from efficiency gains during plan term will be shifted to customers
- ◆ Most examples of PBR plan terms in energy are in the 3 – 7 year range prior to rebasing
- ◆ Why rebase, particularly if there are other sharing provisions?
 - Inherent risk that prices will become divorced from “just and reasonable” level

Off-ramps and Termination Provisions

- ◆ Most plans contemplate some ability to terminate (by regulator or utility) due to uncontrollable events, e.g., force majeure
- ◆ Ability to “opt-out” or terminate prematurely creates potential asymmetry in plan
 - National Grid (Massachusetts) last month filed to terminate its existing comprehensive 10-year PBR plan in year 7 and shift to a partial (O&M only) rate adjustment plan on the grounds that changes in its business and regulatory environment created undue capital cost recovery risk under the comprehensive plan

Benefit Sharing Provisions

- ◆ We've already seen that rebasing at the end of the plan term is a form of benefits sharing, and which can have an effect on efficiency incentives generated by the plan
- ◆ Other forms of benefit sharing provisions:
 - Reduced “going-in” rates
 - “Stretch factor” applied to X
 - “Glide path” for subsequent plan term
 - Earnings sharing formulae

Attributes of Alternative Benefit Sharing Mechanisms

- ◆ Other than “earnings sharing,” the other approaches all serve to alter the price trajectory in a way that passes benefits to customers at various times
 - Rebasing at end of plan term postpones the sharing of benefits until the end of the plan
 - A “glide path” in the subsequent plan term postpones benefit sharing even longer and creates stronger incentives
 - Lower “going-in” rates shares some anticipated benefits with customers up-front
 - A “stretch factor” addition to X lowers the slope of the price trajectory and shares benefits over the plan term

Earnings sharing

- ◆ Typically based on an annual determination of earnings performance (ROE) relative to the allowed ROE
- ◆ Above or below a certain “deadband” range, a proportion of any over or under-earning is shared with customers – may or may not be “symmetric”
- ◆ Advantages:
 - Ensures that results in any one year do not deviate significantly from just and reasonable standard – an insurance policy
 - Customers benefit immediately from any over-earnings, and utility is protected from significant downside
- ◆ Disadvantages:
 - Requires detailed annual financial reporting and assessment
 - Attenuates the efficiency incentives associated with the plan

Service Quality Provisions

- ◆ PBR plans that create incentives for operational efficiency may create disincentives to maintain (or improve) service quality and reliability unless specifically addressed in the plan
- ◆ A service quality incentive mechanism has three requirements:
 - Metrics that cover the range of service quality attributes to be maintained
 - Benchmarks for those metrics
 - Reporting requirement and possibly reward or penalty mechanism to flow through into rates or return
- ◆ Typical metrics that have been used in distribution utility PBR include:
 - Frequency and duration of service interruption
 - Worker safety indicators
 - Service response rates
 - Call-center complaints
 - Customer satisfaction surveys

Wrap-up

Choice of plan terms depends on the key objectives for PBR and a set of economic/policy trade-offs

- ◆ Efficiency incentives versus willingness to tolerate deviations from “normal profit”
- ◆ Strength of incentive versus sharing of benefits and form of sharing mechanism
- ◆ Risk-bearing versus required return on capital
- ◆ Cost reductions versus service quality
- ◆ Regulatory cost versus new monitoring and information requirements
- ◆ Capital versus operating costs
- ◆ Controllable versus uncontrollable costs

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