Project: *Rate-regulated Activities*

Topic: **Analysis of regulatory environments**

Purpose of this agenda paper

1. This agenda paper provides information on <u>different regulatory environments around the world and in what respects regulated activities may be considered different from non-regulated activities</u>. Understanding the effects of regulation and variations in regulations is important for this project because it is these effects on the activities of the entity that is a primary consideration in determining whether it is appropriate to recognise regulatory assets and liabilities.

2. This paper should be read in conjunction with the other agenda papers 11–11H of the July 2010 Board meeting to assist the Board in its deliberations of the *Rate-regulated Activities* project.

3. This paper includes:

    (a) a summary of common regulatory frameworks including:

        (i) a discussion on terminology,

        (ii) a description of the role of the regulator,

        (iii) a description of 'cost-of-service' mechanism,

        (iv) a description of evolving regulatory frameworks,

        (v) a description of 'incentive based' mechanism,

        (vi) a description of common alternative regulatory mechanisms,

        (vii) an overview of a regulatory rate case, and

(viii) the key characteristics of regulations;

(b) accounting implications; and

(c) a staff summary.

Common regulatory frameworks

Terminology – 'cost-of-service' and 'incentive based'

4. The terms 'cost-of-service' and 'incentive based' are historical terms that are commonly used in both current and former standards in national GAAPs. However, the use of these terms and what each of these terms represents is not consistently applied throughout the world. The divergence in views of these terms is expanded upon below in the section on 'evolving regulatory frameworks'.

5. Therefore, while the staff will continue to use these terms for informal discussion/ presentation purposes within these agenda papers, the staff recommend that as this project progresses, new terms be created to appropriately capture those activities that are determined by the Board to be in the scope vs out of the scope of this project. This will assist in the consistent application of this project by all entities using IFRSs.

Role of the regulator

6. In the staff's opinion, regulations and the regulators that create and enforce those regulations have evolved over time based on the dual need by the entities being regulated and 'the common good' (ie the aggregate customer base). Given the capital intensive nature of most entities that are subject to rate regulation, there is a significant need for financing to support the creation of the infrastructure the entity will use in its activities. Without regulations there is a threat that other market participants may enter the market and potentially duplicate the significant infrastructure (by also incurring significant costs) and that may impair the entity's ability to fully recapture the value of the infrastructure. Regulations often preclude other market participants from entering a particular service area.

7. Additionally, given the captive customer base that is common with regulated activities (due to the lack of competition created by regulations), the regulator has a responsibility to ensure the rates charged to customers are balanced with the needs of the creditors and equity holders of the entity. In the absence of the regulator having a responsibility to act on behalf of the aggregate customer base, the entity, commonly in a monopoly position, would have free rein to charge whatever prices the entity would desire.

8. Finally, regulations are usually only created to cover the provision of goods and services that most governments believe are basic necessary items (ie ‘essential’ goods and services) and only where there is often a lack of competition (due to the capital intensive nature of the activities or otherwise).

Cost of service mechanism

9. In its purest form a ‘cost-of-service’ mechanism requires that all costs incurred by an entity will be included in the determination of current or future rates to ensure full recovery of all costs plus a return to compensate for the time value of money and the risk premium required by creditors and equity providers to fund any timing differences in cash flows and the investment in assets.

10. Common costs that are considered to be outside the control of management are frequently included in regulatory deferral and variance accounts (DVAs) and include but are not limited to, gas commodity price change pass-through variance accounts or electricity market price pass-through variance accounts. That is, raw material costs purchased by the entity in order to deliver the goods or services subject to rate regulation.

11. Historically, cost-of-service mechanisms have provided the recovery of most costs provided they were deemed by the regulator to be ‘prudent’. In the past few decades, increased pressures on costs being charged in rates has resulted in more detailed reviews of all costs. A trend towards permitting costs that are determined to be outside the control of management (for example DVAs) to be fully recovered and an alternate trend of incorporating ‘incentives’ in calculating the amount of recovery permitted for costs that management has the ability to influence.

Evolving regulatory frameworks

Background

12. The regulatory frameworks and underlying mechanisms used in the utility industry are continually evolving. In the 1970's, most jurisdictions in the US and some other parts of the world used regulatory mechanisms that were more purely 'cost-of-service' whereby any cost incurred by a regulated entity would be permitted reimbursement unless the cost was deemed to be flagrantly outside of the regulatory mechanism (ie not prudent). During that time, in other parts of the world many utility entities were still under the control of federal or local governments.

13. Since that time, many jurisdictions have modified the mechanisms used to review and determine the authorised rates to be charged by utility entities and in some cases de-regulated and/ or privatized the utility entities. These changes have resulted in a move away from the traditional cost-of-service model of regulation to incentive based models and hybrid models.

14. Appendix A to this paper provides additional details and analysis on the issue of several of pieces of US GAAP guidance issued in an attempt to address the evolving regulatory frameworks.

15. Appendix B to this paper provides recent articles evidencing changes in the regulatory environment.

Incentive based mechanism

16. Incentive based mechanisms incorporate targets determined by the regulator at the beginning of a rate period. The targets could be based on several different factors such as total revenue, price per unit, industry average costs, etc., but always attempt to get an entity to provide the goods or services to the customer in a more efficient manner. If an entity is able to successfully operate the business with costs less than targeted by the regulator, the entity will have an increased profit margin. Unlike the cost-of-service mechanism, an increased profit margin above the target determined by the regulation is not required to be returned to customers through future rates. Therefore, the entity, and ultimately its equity holders, are 'incentivised' to operate the entity as efficiently and cost

effectively as possible. (In setting these incentive targets, the regulator often uses 'best in class' operating efficiencies or current costs of the entity incorporating cost freezes or even reductions in estimated future costs.) Similarly, if an entity incurs costs in excess of the targets determined by the regulator, the entity has a corresponding decrease in its profitability.

17. In some jurisdictions, such as is common in North America, most utility industries were privately owned and operated, but were subject to regulations. In many other jurisdictions around the world, local governments owned or controlled most utility industry entities up until the past few decades when the concepts of privatization and deregulation became more popular. Given the relative newness of these regulatory environments, the regulations created in these jurisdictions started from a more organised basis and commonly incorporated many more incentive based mechanisms. That is, some regulatory environments are evolving from cost-of-service to incentive based, whereas others were created as (and have always been) incentive based.

18. The introduction of price caps, the use of industry averages (often a 'best in class' cost structure) and other pricing mechanisms are all attempts by regulators to incentivise entities to operate more efficiently with an end goal of keeping rates charged to customers as low as is reasonably possible.

Alternative regulatory mechanisms

Alternative revenue programs

19. Alternative revenue programs are becoming more and more common. Alternative revenue programs can typically be grouped into two different types:

    (a) Type A programs <u>adjust billings</u> for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts). This type of plan is meant to create a level of independence between billings charged to customers and sales volumes in order to cover potential losses from fixed costs that were not fully covered because of lower than expected sales volumes, etc.

(b) Type B programs provide for additional billings (incentive awards) if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

20. Both types of programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events. Such adjustments can also result in refunds to customers (for example, if actual sales to ratepayers are higher than expected or if specified performance targets are not met). Appendix A to this paper includes a summary of the US GAAP specific guidance on these alternative revenue programs.

Revenue decoupling

21. 'Revenue decoupling' is a ratemaking mechanism to eliminate/ reduce the link between an entity's profitability and its sales. That is, it's a mechanism that removes the variability in sales volumes from the determination of whether the entity is profitable or not. Revenue decoupling is a specific form of the Type A alternative revenue program noted above.

22. Appendix C to this paper provides an article from The Electricity Consumers Resource Council (ELCON) issued January 2007 on Revenue Decoupling including an introduction, discussion of how revenue decoupling works and specific positions and recommendations of ELCON.

Cap mechanisms

23. The regulator may include a cap on the entity with regards to either the price per unit able to be charged by an entity or a cap on the total revenue permitted to be charged by the entity. When a unit price cap is required by the regulator, the entity is not permitted to charge a rate per unit in excess of the rate determined by the regulator with any costs incurred in excess of the cap being disallowed for reimbursement in either the current or future periods.

24. When a total revenue cap is required by the regulator, in some jurisdictions the entity is able to retain the benefits of charging higher prices (subject to the total revenue cap not being hit) provided the entity can efficiently manage costs. This is consistent with other 'incentive based mechanisms'. In other jurisdictions, the entity is subject to a total revenue cap, but any shortfall/ excess in total revenues

in one rate period is required to be incorporated into future rates through the increase/ decrease in rates charged in the future period. This type of total revenue cap focuses the regulator's power on the revenue line and does not directly focus on the underlying costs of the entity; however, most total revenue caps are determined after a detailed review of the historical costs incurred by an entity and historical and estimated future volumes.

Industry averages

25. As a means to both incentivise and a practical accommodation, it has become more common for regulators to use industry averages to determine specific components of an entity's costs or even the entire estimated cost structure of the entity. These industry averages can then be incorporated into a regulatory structure that is otherwise similar to a 'cost-of-service' mechanism, except that the deemed costs are based on hypothetical industry average costs and not the specific costs of the entity. The industry averages can also be incorporated into the determination of incentive based targets (at either the rate per unit or total revenue level), whereby if an entity operates more efficiently than the industry average the entity, and ultimately the entity's equity holders, are able to keep the positive benefits. The converse is also true if the entity performs worse than the industry averages used to determine rates.

26. One example is the use of a generic cost of capital determined by the regulator for all entities in that jurisdiction. For example Footnote 5a of Fortis Alberta's 2009 annual report[1] states:

> *2009 Generic Cost of Capital Decision Deferral*
>
> In 2009, the Corporation received the Generic Cost of Capital Decision 2009-216 from the AUC. This balance reflects the 2009 impact of this decision which resulted in an increase in the deemed equity capitalization for the Corporation from 37% to 41% and an increase in ROE from 8.51% to 9.00%. This balance is expected to be collected from customers in 2010. In the absence of rate regulation, electric rate revenue would have been $4.1 million lower in 2009.

[1] http://www.fortisalberta.com/data/1/rec_docs/727_2009_Annual_FINAL.pdf

Inflation indices

27. In some jurisdictions, regulators incorporate the use of formulae linked to inflation or similar indices like the consumer price index (CPI) or retail price index (RPI). These formulae provide a practical accommodation for regulators and entities in ensuring timely rate adjustments. However, the use of these formulae do not ensure either the full recovery of costs incurred by an entity or that rates remain as low as possible to the benefit of the customers because there is no on-going or periodic comparison between the actual costs incurred by the entity and the formulae derived rates required by the regulator. When this comparison does occur it is almost exclusively done to determine an appropriate rate to be used prospectively and with no 'true-up' of past variances between actual costs incurred and formulae derived rates.

28. For example page 18 of National Grid's 2010 Annual Report[2] states:

> **UK**
>
> *In the UK, energy networks are regulated by the Office of Gas and Electricity Markets (Ofgem). Ofgem operates under the direction and governance of the Gas and Electricity Markets Authority and has established price control mechanisms that restrict the amount of revenue that can be earned by regulated businesses*
>
> We have eight price controls in the UK, comprising: two for our UK electricity transmission operations, one covering our role as transmission owner (TO), and the other for our role as system operator (SO); two for our gas transmission operations, again one as TO and one as SO; and one for each of our four regional gas distribution networks. The revenue that we can earn from charging for access to our UK electricity and gas systems is determined by formulae linked to the UK retail price index (RPI). These formulae are based upon Ofgem's estimates of operating expenditure, capital expenditure and asset replacement, together with an allowed rate of return on capital invested in the business, as measured by the regulatory asset value. They provide a financial incentive to operate and invest efficiently and also provide incentives by which we can gain or lose for our performance in managing system operation, in controlling internal costs and for our service quality.

[2] http://www.nationalgrid.com/NR/rdonlyres/F25ACBA9-63BC-4BFD-A7E0-E87ED1AEEA99/41619/Annual20Report202010.pdf

Overview of a regulatory rate case

29. The process of reviewing and finalising rates authorised by the regulator is complex and time consuming in all jurisdictions. This is true for both jurisdictions determined to be 'cost-of-service' and 'incentive based'.

30. Appendix D to this paper provides an article from Regulatory Research Associates titled *The Rate Case Process: A Basic Guide (a.k.a.: Regulation for Dummies)* published on 17 February 2010. This article points out several changes that have occurred in the last few decades and the changing viewpoint of many regulators regarding rate freezes, disallowed costs, incentive mechanisms, etc.

Key characteristics of regulations

31. In the staff's opinion, the key characteristics of regulations that should be considered in determining the economic implications and resulting accounting implications include:

    (a) the regulations that govern the interaction between the regulator, entity and customer;

    (b) the rights provided to the entity by the regulator permitting the entity to operate in a jurisdiction;

    (c) the obligations of the entity to provide goods and services at the rates determined by the regulator (that has a responsibility to balance the interests of the customers and the entity's equity holders);

    (d) the specific regulatory mechanism in place and whether it is a direct cost-of-service reimbursement, incentive based or a combination of both (ie hybrid) mechanism;

    (e) determining if the regulatory mechanism has any alternative mechanisms like unit price caps, total revenue caps or incentives for meeting other targets (like efficiency factors or service level factors); and

    (f) determining whether any of these components are adjusted through a prospective rate making process (whereby prior variances are used as an input to determining future rates, but for which there is not direct link/ recovery in future rates).

Accounting implications

32. Paragraph 49(a) of the Framework defines an asset as follows:

> An asset is a resource controlled by the entity as a result of past events and from which future economic benefits are expected to flow to the entity.

33. As discussed in more detail in Paper 11D *Comparison of RRA project to current IFRSs* of the July 2010 Board meeting and specified in paragraphs 13–16 of IAS 38 an intangible asset may be 'controlled' in a number of ways including 'a restraint of trade agreement'. In the context of regulated activities, the entity often has exclusive rights to operate in a delimited service area either as a direct result of the regulations or because the entity has a natural monopoly over a captive customer base. In the staff's opinion, these are supportive of the recognition of a regulatory asset.

34. Other factors to be considered are discussed in more detail in Paper 11C *Analysis of Scope (unit of account)* of the July board meeting and include:

    (a) the level at which regulations are applied (ie the unit of account issue), and

    (b) the ability to determine a cause and effect relationship (ie linkage) between past transactions and the corresponding creation of future economic benefits.

35. Appendix E to this paper provides excerpts of an article in the Weekly Credit Edge published by BMO Capital Markets Research dated 22 March 2010. This article provides an overview of IFRS considerations in the Pipelines and Utilities entities.

Staff summary

36. Most regulatory environments around the world are evolving and will continue to evolve. Based on recent history, cost-of-service mechanisms continue to play a diminishing role in the determination of the rate required by regulators. Additionally, regulators acting in their fiduciary capacity on behalf of the aggregate customer base continue to review and scrutinise costs to ensure they are prudent.

37. In the staff's opinion, the most difficult aspect the Board will need to consider in this RRA project is the determination of whether the entity has 'control' over incremental future economic benefits that have been created as a result of current period costs. Factors to be considered in this determination include:

    (a) the concept of the aggregate customer base;

    (b) the concept of the delimited service area over a captive customer base; and

    (c) the individual transaction level (or higher) unit of account.

Appendix A – Authoritative US GAAP documents and analysis

A1. Several of the authoritative US GAAP documents are:

(d) FAS 71 *Accounting for the Effects of Certain Types of Regulations* (issued December 1982) [link]

(e) FAS 90 *Regulated Enterprises – Accounting for Abandonments and Disallowances of Plant Costs – an amendment of FASB Statement No. 71* (issued December 1986) [link]

(f) FAS 92 *Regulated Enterprises – Accounting for Phase-in Plans – an amendment of FASB Statement No. 71* (issued August 1987) [link]

(g) FAS 101 *Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71* (issued December 1988) [link]

(h) FTB 87-2 *Computation of a Loss on an Abandonment* (issued December 1987) [link]

(i) EITF 91-6 *Revenue Recognition of Long-Term Power Sales Contracts* (issued May 1992) [link]

(j) EITF 92-7 *Accounting by Rate-regulated Utilities for the Effects of Certain Alternative Revenue Programs* (issued May 1992) [link]

(k) EITF 92-12 *Accounting for OPEB Costs by Rate-Regulated Enterprises* (issued January 1993) [link]

(l) EITF 93-4 *Accounting for Regulatory Assets* (issued March 1993) [link]

(m) EITF 97-4 *Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB Statements No. 71 and 101* (issued July 1997) [link]

A2. Paragraph 1 of FAS 90 states:

> FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation,* was issued in December 1982. Shortly after that Statement was issued, major events in the electric utility industry caused the Board to review the effects of the Statement on the accounting for those events. After considering the application of the Statement, the Board decided to amend Statement 71 to provide more specific guidance for some of those events and to change the accounting for others.

A3. FAS 90 requires that if an entity has an abandonment of an asset (either in use or in construction), the entity shall determine whether a partial or full recovery will be received for the costs incurred to acquire the asset. FAS 90 requires the entity to measure any recovery at its present value using the incremental borrowing rate of the entity. Any difference between the carrying amount of the asset and the present value of its expected recovery is recognized as a loss. This measurement method is different from the cost deferral/ cost accumulation method required by FAS 71.

A4. FAS 92 amends FAS 71 to specify the accounting for phase-in plans whereby a regulator will permit an increase in current rates for anticipated costs to be incurred in a future period. These costs are often associated with the construction of major plant assets.

A5. Paragraphs 8 and 9 of FAS 92 state (emphasis added):

> 8. If specified criteria are met, paragraph 9 of Statement 71 requires capitalization of an incurred cost that would otherwise be charged to expense. <u>An allowance for earnings on shareholders' investment is not "an incurred cost that would otherwise be charged to expense." Accordingly, such an allowance shall not be capitalized</u> pursuant to paragraph 9 of Statement 71.
>
> 9. In specified circumstances, paragraph 15 of <u>Statement 71 requires capitalization of an allowance for earnings on shareholders' investment (a designated cost of equity funds) during construction</u>. Paragraph 5 of this Statement requires capitalization of an allowance for earnings on shareholders' investment for qualifying phase-in plans. <u>If an allowance for earnings on shareholders' investment is capitalized for rate-making purposes other than during construction or as part of a phase-in plan, the amount capitalized for rate-making purposes shall not be capitalized for financial reporting</u>.

A6. The staff are unsure of the rationale for the guidance in FAS 71 as clarified in FAS 92 that explicitly requires the capitalisation of an 'allowance for earnings on shareholders investment' (clarified in footnote 4 of FAS 92 to be 'intended to have the same meaning as the phrase "a designated cost of equity funds"'). This guidance contradicts FAS 34 *Capitalisation of Interest Cost*. Moreover, as stated in paragraph 9 of FAS 92 (see above) the justification is not applied to the return permitted by the regulator for any purposes other than during construction or as part of a phase-in plan.

A7. By December 1998, the FASB issued FAS 101 to provide guidance on situations when an entity determines its prices are no longer regulated and within the scope of FAS 71. FAS 101 includes several examples when an entity's operations fail to continue to meet the criteria in FAS 71 including 'regulatory actions resulting from resistance to rate increases that limit the enterprise's ability to sell utility services or products at rates that will recover costs of the enterprise is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts.'

A8. EITF 92-7 provides guidance on the accounting treatment of certain alternative revenue programs. EITF 92-7 requires the recognition of revenue for alternative revenue programs that can generally be segregated into two categories Type A and Type B:

> Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts). Type B programs provide for additional billings (incentive awards) if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

A9. Both Type A and Type B alternative revenue programs are not considered to be traditional 'cost-of-service' mechanisms which resulted in the issue of the EITF Consensus. Despite the differences in these alternative revenue programs from the scope of FAS 71, 'The Task Force reached a consensus that once the specific events permitting billing of the additional revenues under Type A and Type B programs have been completed, the regulated utility should recognise the additional revenues if [listed] conditions are met.' Since the issue of this Consensus, these mechanisms have increased in their use by regulators and are now common in many jurisdictions around the world.

Appendix B – Recent articles evidencing changes in the regulatory environment

B1. A Utility Regulatory News article from 15 April 2010 includes several articles that point to the ever changing regulatory environment and the uncertainty of future approval and collection of costs incurred in the current period. One representative article is:

> **Commission Denies Nearly Two-thirds of Requested Increase**
>
> The Washington Utilities & Transportation Commission has awarded a combined electric and natural gas utility, Puget Sound Energy, Inc. (PSE), an electric rate increase of $56.2 million (2.8%) and a gas rate increase of $10.15 million (0.8%). The utility had originally sought additional revenues of $148 million (7.4%) and $27.2 million (2.2%), respectively.
>
> The application for new rates had been premised on numerous changes in rate base, highlighted by the company's acquisition of a new generating station, the Mint Farm Energy Center.

B2. A similar article in the Utility Regulatory News from 10 June 2010 notes changes in Vermont's regulatory mechanism to introduce more price caps and non-entity specific indices (ie ROE based on treasury bonds, inflation) into the existing incentive based mechanisms:

> ***Vermont PSB continues alternative regulation plan***
>
> *Weekly Update Courtesy of Utility Regulatory News #3969:* Endorsing the price cap form of regulation for an electric utility, the Vermont Public Service Board has determined that the utility had been able to strengthen its financial position as a result of its alternative regulation plan (ARP).
>
> The board found that the utility, Green Mountain Power Corp., had instituted an ARP that was in the best interests of its ratepayers and that the ARP, as compared to traditional cost-of-service rate making, allows the utility to respond more quickly and effectively to changes in operating costs. Nevertheless, the board agreed that some updating was needed. To that end, the board authorized both the retention of the salient features of the utility's existing ARP and the addition of certain new provisions. One of the terms kept from the current plan is an annual adjustment to the utility's rate of return on equity (ROE) based on yields from 10-year Treasury notes. However, the new plan offers a revised performance-based adjustment for ROE, under which Green Mountain Power's efficiency and productivity will be measured against a benchmark group of utilities. The updated ARP also includes an inflation-adjusted capping mechanism for non-power costs, whereas the existing plan relied on a fixed dollar ceiling for such costs.
>
> The board deemed the ARP changes appropriate given the collective experience of electric utilities operating under ARPs in the state. In the board's view, the modified plan will facilitate more accurate capture of the impacts of inflation over time.
>
> Observing the continued volatility in both energy and financial markets, the board ruled that such inflation adjustments marked a significant improvement in the utility's ARP.

B3. An example of the increasing level of scrutiny on costs and the increasing potential for disallowed costs that had been incurred in prior periods being released and recognised in the current period statement of comprehensive income is Footnote 2 of Entergy's 2009 Annual Report which states, in part (emphasis added)

> **Filings with the APSC (Entergy Arkansas)**
>
> <u>Retail Rates</u>
>
> *2006 Base Rate Filing*
>
> In August 2006, Entergy Arkansas filed with the APSC a request for a change in base rates. Entergy Arkansas requested a general base rate increase (using an ROE of 11.25%), which it subsequently adjusted to a request for a $106.5 million annual increase. In June 2007, after hearings on the filing, the APSC ordered Entergy Arkansas to reduce its annual rates by $5 million, and set a return on common equity of 9.9% with a <u>hypothetical common equity level lower than Entergy Arkansas' actual capital structure</u>. For the purpose of setting rates, the <u>APSC disallowed a portion of costs associated with incentive compensation based on financial measures and all costs associated with Entergy's stock-based compensation plans</u>. In addition, under the terms of the APSC's decision, the order eliminated storm reserve accounting and set an amount of $14.4 million in base rates to address storm restoration costs, <u>regardless of the actual annual amount of future restoration costs</u>. The <u>APSC's June 2007 decision left Entergy Arkansas with no mechanism to recover $52 million of costs previously accumulated in Entergy Arkansas' storm reserve and $18 million of removal costs associated with the termination of a lease</u>.
>
> The APSC denied Entergy Arkansas' request for rehearing of its June 2007 decision, and the base rate change was implemented August 29, 2007, effective for bills rendered after June 15, 2007. In December 2008 the Arkansas Court of Appeals upheld almost all aspects of the APSC decision. After considering the progress of the proceeding in light of the decision of the Court of Appeals, <u>Entergy Arkansas recorded in the fourth quarter 2008 an approximately $70 million charge to earnings</u>, on both a pre- and after-tax basis because these are primarily flow through items, <u>to recognize that the regulatory assets associated with the storm reserve costs, lease termination removal costs, and stock-based compensation are no longer probable of recovery</u>. In April 2009 the Arkansas Supreme Court denied Entergy Arkansas' petition for review of the Court of Appeals decision.

Appendix C – Revenue Decoupling

C1. The article below titled *Revenue Decoupling, A Policy Brief of the Electricity Consumers Resource Council* was published in January 2007.

Revenue Decoupling

A Policy Brief of the Electricity Consumers Resource Council

Every complex problem has a simple solution too good to be true, and it usually is.
Attributed to H.L. Mencken

Introduction

For over two decades advocates of ratepayer-funded energy efficiency and load reduction programs have recommended that the 'link' between utility's revenues and its sales be 'decoupled' to eliminate a utility's disincentive to sponsor such programs. The argument is that the combination of the utility management's fiduciary duty to shareholders and the use of rates based on a revenue requirement, that includes sales in its calculation, discourages utilities from being competent vendors of energy efficiency and load reduction services.

Revenue decoupling (RD) is generally defined as a ratemaking mechanism designed to eliminate or reduce the dependence of a utility's revenues on sales. It is adopted with the intent of removing the disincentive a utility has to administer and promote customer efforts to reduce energy consumption and demand or to install distributed generation to displace electricity delivered by the utility's T&D system. In regulatory parlance, RD takes the form of a tracker or attrition allowance in which authorized per customer margins are subject to a true-up mechanism to maintain or cap a given level of revenues or revenues per customer. Variations from the targeted sales or revenues are subsequently recaptured from ratepayers through a surcharge or credit.

In a significant departure from traditional cost-of-service principles, which historically provides utilities with only the opportunity to earn a fair return, RD guarantees actual earnings at the level of authorized earnings. Under RD, a utility is indifferent to the impact of sales levels or when the sales occur because of changing economic conditions, weather, or new technologies.

ELCON members are strong supporters of energy efficiency and are world-class practitioners of innovative technologies that reduce their energy costs to improve their competitiveness. But ELCON strongly opposes decoupling because it disrupts and distorts the utility core business functions and is not a particularly effective way of promoting energy efficiency or anything of benefit to customers. Time and time again decoupling has been tried in several states, only to be suspended because it unduly interferes with the overall regulatory process. ELCON believes that there are other ways to promote energy efficiency and load reduction services that have proven to be more effective. This paper describes the simple mechanics of decoupling, why decoupling has historically failed and is not likely to be any more effective in future applications, and proposes alternative regulatory policies that more effectively focus on market transformation and the effective delivery of demand-side services.

The Mechanics of Revenue Decoupling

An Illustrated Example of An Annualized RD Mechanism [1]

Base Year Assumptions

	Year One	Year Two
Utility's Operating Costs (A)	$4 billion	$4 billion
Utility's Rate Base (B)	$5 billion	$5 billion
Authorized Return to Equity Owners (ROE)	10%	10%
Authorized Earnings to Equity Owners (C) (10% of $5 billion)	$500 million	$500 million
Utility's Authorized Revenue (A + C)	$4.5 billion	$4.5 billion
RD Balance Account (D)	0	$45 million
Baseline Sales (E)	45,000 GWh	45,000 GWh
Base Rate per KWh (A + C)/E	$0.10	$0.10
Effective Rate per KWh (F) (A + C + D)/E	$0.10	$0.101

Actual Sales Year

	Year One	Year Two
Actual Sales (G) (1% deviation from baseline forecast)	44,550 GWh 1% Below Baseline	45,450 GWh 1% Above Baseline
Actual Revenues Collected (H) (F × G)	$4,455 million	$4,590 million
Unadjusted Earnings to Equity Owners (I) (H minus A)	$455 million	$590 million
Reported ('Authorized') Earnings (C)	$500 million	$500 million
Actual ROE (I/B)	9.1% Reduction of 90 bps	11.8% Increase of 180 bps
Reported ('Authorized') ROE	10%	10%
End-of-Year Balance Account (D) (A + C) minus H	$45 million	($90 million)

[1] This is a simplified example of revenue decoupling that assumes no variable T&D costs or change in the number of customers. Also, tax implications and accounting for price elasticity are ignored.

How Decoupling Works

RD mechanisms can take several forms but all accomplish the same thing: customer rates are automatically adjusted to immunize utility earnings from sales fluctuations.

The first example is illustrated on the spreadsheet on page 2. It provides a simplified form of mechanism in which true-ups are done on an annual or multi-year basis. The process usually starts with a baseline determination of a utility's revenues that may include the anticipated consequences of a DSM program. This is the 'base case' in the illustration.

The illustration holds this baseline constant over a two-year period. In the first year, actual sales are 1% below the baseline amount; in the second year actual sales are 1% above the baseline. The result is a revenue shortfall in the first year of $45 million. Absent any other offsetting revenue recovery mechanism, this shortfall reduces earnings to equity owners and the expected ROE. This illustrates a main argument of proponents of RD that any small reduction in sales can produce a significant reduction in the utility's allowed earnings. In the example, the actual ROE is 9.1%, a reduction of 90 basis points from the allowed ROE of 10%.

Applying the RD mechanism in the second year, revenues are adjusted by increasing the customer rate upwards to ensure that sufficient revenues are collected to achieve the allowed ROE. However, actual sales are 1% above the baseline amount and the utility over collects $90 million. The actual ROE is 11.8% or 180 basis points above the allowed ROE. This simple example highlights the potential year-to-year volatility of the RD mechanism.

With compounding economic events (e.g., recessions), the accrual account can grow quite large unless more frequent rate cases or true-ups are ordered. RD mechanisms tried in the past tended to generate substantial accruals that quickly became a dilemma for regulators and a burden for ratepayers.

The second example (on page 4) illustrates decoupling on a revenue-per-customer (RPC) basis. The base year revenue collected per customer (RPC) on an average customer class basis is fixed, and the annual charge is then typically allocated on a monthly, normalized basis over a reference year. Each month the actual revenues collected per ratepayer are compared to the allowed monthly RPC and the difference is either credited or debited to a balancing account. Customers would still be billed on a per-unit consumption basis, but the rate would be trued-up based on actual revenues collected per customer. This prevents the utility from earning additional profit from unexpected sales but also ensures that the utility recovers its costs resulting from unexpected customer growth. For unexpected declines in sales per customer and/or declines in the number of customers, the mechanism works the same way. Under- or over-recoveries in any month are automatically trued-up the following month or at the end of the year.

The RPC mechanism highlights the 'blunt instrument' nature of decoupling. The utility is made whole for earnings losses that go beyond the limited losses caused solely by energy efficiency and load reduction programs. The net effect of the true-up mechanism is to put the utility's revenue stream on autopilot. This isolates utility management and equity owners from the normal business risk inherent to the utility industry, notwithstanding that the existence of a ROE is to reward equity owners with a return on their investment that includes a sizeable risk premium commensurate with the business risk. In short, an RD mechanism makes retail electric distribution service virtually risk free for utilities.

The Mechanics of Revenue Decoupling

An Illustrated Example of Revenue-Per-Customer (RPC) Mechanism With Monthly True-Ups 2

Base Year Allowed RPC

For a Base Year Month

Base Year Rate per kWh (A)	$0.10
Base Year (Month) Sales in kWh (B)	1 billion
Base Year (Month) Revenue.......................... (A x B)	$100 million
Base Year Number of Customers (C)	1,000,000
Allowed RPC .... (A x B)/C	$100

Calculation of Revenue Adjustment

For A Single Month

Base Year Rate per kWh (A)	$0.10
Actual Sales for the Month (D) .... 5% Reduction from Baseline (B)	0.95 billion
Actual Revenues for the Month (E).................. (A x D)	$ 95 million
Actual Number of Customers (F)	1,010,000
Allowed RPC	$100
Allowed Revenues (G) .... (F x E)	$101 million
Revenue Adjustment (H) .... (G – E)	$6 million
Forecasted Next Month Sales (I)	1.0 billion
Rate Adjustment (True-Up) .... (H/I)	$0.006

This adjustment is added to rates for sales the following month, or at the end the year.

2 This example assumes that sales per customer decline but the number of customers grows.

ELCON Position & Recommendations

A. Decoupling Promotes Mediocrity In The Management Of A Utility.

The primary function of a regulated electric utility is and will always be to efficiently sell and deliver electric energy to customers. For investor-owned utilities, the profit-motive is a legitimate and practical means to incent utility managers to operate their business in a competent and efficient manner. There also need not be any conflict with 'unselling' the business' primary product by offering energy efficiency and load reduction services.

Firms in many industries meet the competition by selling a range of products competing for different segments of the market share. But in regulated industries, such as electric utilities, rate structures and regulatory policies may have to be aligned to make this work. The attractiveness of revenue decoupling to many utility executives is that it will immunize the company's earnings or revenues from sales fluctuations. This can only promote mediocrity and indifference to the utility's core business, a situation that should not be in the best interests of either advocates of selling or unselling the energy product.

B. Decoupling Shifts Significant Business Risk From Shareholders To Consumers With Only Dubious Opportunities For Net Increases In Consumer Benefits.
Decoupling does not create an economic incentive promoting greater energy efficiency or load reduction. It establishes, at best, utility indifference to these objectives. At the same time, it undermines customer efficiency efforts and muddles price signals to consumers. For example, conservation efforts are rewarded with higher future rates, while excessive consumption paradoxically produces bill credits. This is a cynical way to induce energy conservation that is not likely to be effective. Decoupling only removes an alleged disincentive while at the same time creating real disincentives for competent management of the business. The Maine Public Utilities Commission stated in 2004:

> Revenue decoupling does not … provide any positive incentive for utilities to promote or support energy efficiency or conservation programs; it only makes them financially neutral to such activities.

There is growing national concern that utilities are under-investing in infrastructure and not adequately planning for the future needs of their customers. Why this situation has been allowed to happen is troublesome given that for many utilities their allowed return is already above their actual cost of capital. Regulatory policies need to refocus utility management on its core responsibilities to efficiently sell and deliver electric energy and to make prudent long-term investments. Regulators must not bargain with their utilities from a weak position that assumes that financial incentives in excess of a reasonable return is necessary for ordinary business behavior. For all practical purposes RD mechanisms put utility management on autopilot and this will only further encourage them to ignore their core business, the value of economic development in their franchise area, and the broader needs of the utility's customers. These objectives are at least as important as any attempt to only eliminate a disincentive to energy efficiency.

An important feature of the financial structure of investor-owned utilities is that the utility's shareholders assume normal business risk. This is the risk-reward model that pervades private businesses in the US and global economies. Shareholders are best able to diversify business risk and market-based economies strive on this basis. Utility ratepayers are least able to do so; yet it is the expressed intent of RD mechanisms to shift risk from shareholders to consumers, a radical departure from standard regulatory policy intended to balance the interests of equity owners and ratepayers.

Proponents of RD mechanisms almost always support preserving the utility's allowed return on equity at a level that assumes the shareholders retain such risk. Getting utility management to buy into the scheme would be difficult otherwise. Hence RD mechanisms are an attempt to force energy efficiency and load reduction programs at any cost and with no regard for the economic welfare of the impacted ratepayers.

Using RD mechanisms in conjunction with general rate cases also can have a ratchet effect on revenues and rates to the extent the RD adjustments in between rate cases are memorialized in the next rate case. For these and other reasons there is ample justification for dismissing the alleged value of RD mechanisms in ratemaking.

C. Decoupling Eliminates A Utility's Financial Incentive To Support Economic Development Within Its Franchise Area. This Includes The Incentive To Support The Well Being of Manufacturers And Their Workforce.

Promoting growth in sales through the addition and expansion of business enterprises is a key area where utility financial incentives and local public interests are precisely aligned. Revenue decoupling breaks that alignment. While its sole purpose is the elimination of the alleged disincentive to a utility's active support for energy efficiency and load reduction programs, it also eliminates the financial incentive to actively promote the economic development of the utility's franchise area. More specifically, it neutralizes the financial incentive to attract new commercial and industrial businesses—and new job opportunities—to the utility's franchise area, and to support the well being of its existing commercial and industrial customers, unless those customer classes are specifically exempt from the RD mechanism. ELCON believes that regulatory policies should promote greater customer focus, not less.

D. Revenue Decoupling Mechanisms Tend To Address 'Lost Revenues' And Not The Real Issue, Which Is Lost Profits.

To the extent that rates based on sales create a disincentive for utility efforts to promote energy efficiency and load reduction, the problem is in the rate design and the failure to abide by longstanding cost-of-service ratemaking principles. RD mechanisms have the effect of shifting the recovery of the utility's fixed costs into the customer (or demand) charge of base rates where they belonged in the first place. Thus, from one perspective, RD can be viewed as a stopgap ratemaking mechanism to overcome rate designs that have been used and abused for other misguided policy objectives such as the imposition of cross-class subsidies and stranded cost recovery. The complexity of RD mechanisms also makes them very expensive to administer and regulate. This greatly reduces the transparency of the ratemaking process and, even more so in the public mind, reduces the logic of cost causation.

The ability of a utility to have the opportunity to earn a fair return on assets that are prudently incurred and that remain used and useful is a grand compromise of regulation that has withstood the test of over a hundred years of practice. Any increased opportunity for a utility to earn its authorized rate of return must be commensurate with an increase in business risk, not the reverse!

There is no inherent inconsistency that a utility would both sell and 'unsell' electric energy if rates are appropriately designed for the different services. Selling competing products and services is a common business choice and need not be a moral dilemma only for utility executives. There are examples of state ratemaking practices such as shareholder performance incentives that create more explicit economic inducements for promoting energy efficiency and load reduction. These practices avoid the collateral damage created by the 'blunt instrument' nature of RD mechanisms.

E. The First And Most Important Step Regulators Can Take To Promote Energy Efficiency Is To Send The Proper Price Signals To Each Customer Class.

In the short term, seasonal weather variations are the predominant cause of variations from sales forecasts. For example, unseasonably mild winters can lead to below forecast sales. In the longer term, economic growth in the form of increased customer accounts and usage drive electric sales and revenue growth. Ratepayer investments in energy efficiency gradually moderate energy sales growth. Load shifting efforts from peak to off-peak periods may not reduce overall kWh sales, but should lower the cost of supplying that energy.

Thus the first and most important step regulators can take to ensure that ratepayers themselves are induced to make energy efficient investments and behavioral changes is to implement retail rates that send the proper price signals to each customer class. This includes allocation of fixed costs to customer (or 'demand') charges and time-variant energy charges. The Energy Policy Act of 2005 directs the states to consider expanded deployment of time-based pricing and advanced metering, and ELCON strongly encourages states to pursue this path to more efficient pricing rather than the futile pursuit of decoupling mechanisms. Large industrial customers are almost always on some form of time-of-use rate, with a demand charge, and this rate structure is extremely valuable to the customer for evaluating the cost effectiveness of energy efficiency improvements in their manufacturing facilities. Large industrial customers do not look for guidance from utilities on how to co-optimize their energy consumption and manufacturing activities, and 'decoupling' does not make utilities experts in these matters. By further blunting price signals to ratepayers, RD mechanisms actually undermine incentives for customers to invest in more efficient appliances and equipment because the reward for reducing consumption is higher rates in the future. ELCON members believe that a utility's fundamental responsibility is to efficiently sell and deliver energy at the lowest possible cost, and appropriate price signals are an essential component of that objective.

F. Several States Have Successfully Used Alternative Entities—Including Government Agencies—For Unselling Energy. This Creates An Entity Whose Sole Mission Is To Promote Energy Efficiency, And Retains A Separate Entity Whose Responsibility Is To Efficiently Sell And Deliver Energy.

Some states believe that simultaneously selling and unselling electric energy is a real conflict of interest and have assigned the administration of the unselling function to an independent entity or agency whose mission is dedicated to promoting energy efficiency and load reduction. This policy recognizes that another entity—the utility—must be responsible for efficiently selling and delivering electric energy. States that have taken this path are Wisconsin, Maine, New Jersey, Ohio, Vermont, Oregon, New York, and Connecticut.

In New York, for example, the New York State Energy and Research Development Authority (NYSERDA) is charged with the responsibility for demand-side programs, and is funded by a systems benefit charge that is collected by the utilities. Wisconsin established *Focus On Energy* as a public-private partnership offering energy information and services to residential, business, and industrial customers throughout the state. There services are delivered by a group of firms contracted by the Wisconsin Department of Administration's Division of Energy.

Appendix D – The Rate Case Process: A Basic Guide

D1. The article below titled *The Rate Case Process: A Basic Guide (a.k.a.: Regulation for Dummies)* was published by Regulatory Research Associates on 17 February 2010. [Reproduced with permission.]

THE RATE CASE PROCESS: A BASIC GUIDE
(a.k.a.: REGULATION FOR DUMMIES)

Due to the resurgence in rate case activity, we have assembled a "primer" on how a rate proceeding is conducted. Rate case activity has certainly increased over the last few years – in 2009, 95 major electric or gas retail rate cases were decided nationwide, versus 82 rate case decisions in 2008, 94 in 2007, 67 in 2006, 70 in 2005, 61 in 2004, and 42 in 2003. At the current time there are 83 major electric or gas retail rate cases pending in the U.S.

As many companies gear up for a new round of rate cases, it is our understanding that utility managers have had to re-educate themselves on the regulatory process, as it may have been 10 years or more since they last were involved in a traditional rate proceeding. In the early 2000's, there was a dearth of rate case activity. For example, in 2001, there were a total of 31 electric and gas decisions. There were various reasons for this level of regulatory activity. Interest rates were relatively low, and many utilities had previously been authorized rates of return that were deemed to be much higher than what were being awarded in then-prevailing rate proceedings. Also, construction activity was down during this period, and there may have been no large capital investments for which utilities would typically seek rate recognition. Additionally, technological improvements that reduced utility costs may have caused a delay in the filing of a rate proceeding.

However, many utilities stayed out of the rate case arena during that time because of the advent of electric industry restructuring in many states. In the late-1990's, "competition" was the industry buzzword, and many utilities in the industry were trying to minimize their retail prices and remain competitive. In several states, the utility commissions established multi-year rate plans, under which rates were frozen in an attempt to allow utilities to recoup stranded costs, the costs that would be unrecoverable in a competitive market. Several companies have recently completed or are now in the latter stages of these multi-year restructuring plans, and as these plans come to an end, these utilities are permitted to request rate increases only for their delivery rates, as their generation rates may now be subject to the competitive market.

During these rate freezes, utility companies had to absorb any increases in operating costs (e.g., labor, health case, pension, etc.) that occurred, and as a result, profit margins were compromised. Many companies embarked on cost-cutting efforts to support profits during this time, and this led to increased regulatory scrutiny on utility service quality -- the thinking being that utilities would attempt to maintain earnings at the expense of customer service. Additionally, in an effort to boost earnings, some utilities became heavily involved in energy marketing and trading, an avenue that did not provide the boost in profits that many in the industry expected.

Also during this period, it was not clear who would construct the new generation that would be required to satisfy increased power demand and to replace the aging generation infrastructure. Most utilities did not want to bear the regulatory uncertainty associated with the rate increases that would be required and the potential for regulatory disallowances from cost overruns determined after-the-fact. Additionally, the competitive power suppliers were reluctant to construct new generating facilities, given the lack of true market-based pricing in some of the "restructured" states and the uncertainty associated with the long-term retail pricing mechanisms that were established in those states. Now that many of the rate freezes have concluded, and the trend toward expanding competition has died down, rate cases are being filed at a brisk pace, reflecting both increased operating expenses and new investment in electric generation and electric and gas delivery infrastructure.

The discussion that follows provides a very basic description of the rate case process, the reasons why a company may need to file a rate case, and the typical rate case formula used by most of the public utility commissions nationwide.

Determining Prices

The first question that needs to be asked is “why is the provision of utility services a regulated industry?” Utilities are by no means typical companies. In any competitive industry, a customer has many purchasing choices. In the auto industry, or the food industry, customers pick and choose among a variety of providers -- the customer can consider the quality of the product as well as the price. If a seller’s prices are too high or the quality of the product does not meet the customer’s standards, the customer will go elsewhere. Prices in such industries are set by supply and demand in the competitive marketplace.

As we know, the utility industry is quite different. You move into a new town and you are told which utility serves the area. Typically, there’s not much you can do except sign up for the service and pay your bill. Given the monopoly status of these companies, there has to be some controls on pricing because there is no competition to keep prices reigned in. So, this is why we have public utility commissions -- every state has one. These commissions are to make sure that the utilities’ rates allow the companies they regulate to earn what is considered to be an adequate profit commensurate with each company’s investment risk, while ensuring that each utility offers high quality service.

Since there is no market-setting method for the typical utility business, utility rates are based on what we call the "cost-plus method." The regulator looks at all of a utility's prudent costs and prudent capital investments, and then adds a risk-adjusted profit margin for the utility's shareholders. The regulator then takes this total number, which is referred to as the "revenue requirement," and translates it into a per-kilowatt-hour usage-based rate that is used to determine each customer's monthly bill. This sounds very simple, but in reality it is not.

Reasons for Filing a Rate Case

We have established that a utility is a monopoly -- the sole supplier of a product that you cannot live without. So, if your utility decides it needs to raise its prices, can the utility raise prices to whatever level it desires? Of course not. It must file a "rate case" before the state's public utility commission.

At this point you might be thinking about the fact that in certain states customers are able to select a competitive power supplier, as we mentioned earlier. Yes, it is true that the electric utility industry is now competitive in some states, but not for all utility functions. A typical utility has three functions -- generation, transmission, and distribution. And, in most states, all three of these functions are still fully regulated, but in about 15 states, the generation piece is now regarded as competitive, and is no longer traditionally regulated. In some of these "restructured" states, the price of the generation piece for customers who have not selected an alternative supplier is priced through an annual auction. For other restructured states, the power commodity to serve these customers is purchased in the open market by a separate state agency or by the incumbent utility, which in that state is only a regulated deliverer of competitively priced power. And, unless some company is permitted to run a second set of wires down your street and connect those wires to your house, the delivery function will continue to be fully regulated.

The same issues are there for the natural gas industry, with the gas commodity portion of the service being competitively offered in many states, and the delivery piece remaining regulated.

So, why does a utility file a rate case? Maybe the utility's profits are no longer adequate because the company is experiencing rising healthcare or pension costs. Or maybe the economy in its service territory isn't doing as well as expected. Perhaps the company is constructing a new power plant and needs to have this investment reflected in rates, or the company's current rates are no longer providing the utility's investors with an adequate rate of return. And, maybe the profit level set by the regulator in the company's last case is considered too low in today's economic environment.

The Commissioners

In most states, commissionerships are appointed positions, and these appointments are made by the state governor or the mayor in the District of Columbia. However, in 13 states, the commissioners are elected. In two of these states the commissioners are elected by the legislature, but in the other 11, the commissioners are elected by the general population. All else being equal, we attribute more investment risk to those states in which the utility commissioners are elected. If you think about it, how can a commissioner run for election by stating that he or she promises to raise utility rates and to make sure that the utility earns a very strong rate of return for its investors? It is an obvious conflict of interest.

In the 1980's, the Louisiana Public Service Commission, an elected commission, promised not to permit any rate increases despite that fact that its largest electric utilities were constructing nuclear generators that cost billions of dollars. The utilities had to appeal each PSC rate decision, and it was the courts that became the regulators through that period. Also, we note that the timing of an election may affect when a utility files a rate case. For example, if you know that next November there will be an election for three of the five commissioner slots in your state, you will want to time your rate case so that your request will not become an election issue.

Just because we attribute more investment risk to elected jurisdictions, this does not indicate that all of the elected jurisdictions are at the bottom rung of our ratings. If all else was equal, we would have those jurisdictions down at the bottom of our ratings; however, for some commissions, all is not equal. Many years ago, the Alabama PSC, an elected commission, realized that rate increases were required if the state was going to have quality utility service -- so the commission put Alabama Power on autopilot. Periodically, Alabama Power's rates are automatically adjusted based on a variety of issues including the company's earned rate of return. And this happens without the PSC's direct intervention. So the company gets the rate adjustments it needs, and the Alabama PSC stays out of the news. And, we do rank Alabama regulation in our top category, meaning the category signifying the lowest investment risk.

Utility commissions in the U.S. have between three and seven members, most of whom are attorneys, but there are some economists and some accountants as well. There are also some commissioners who run private businesses. All but two commissions in the U.S. have full-time members; all members of the Delaware PSC serve part-time, and in Vermont, the commissioners other than the chairman serve part-time.

The Rate Case Process
A rate case is a judicial process that is usually controlled by a judge called an administrative law judge (ALJ) or a hearing examiner. There is no jury, and the final outcome is determined by the public service commission. In some states, the commission actually presides over the hearings and all aspects of a case, but in most states the commission gets involved at the end, and makes its decision after reviewing the entire record in the case.

The process begins with the company's filing. Usually about five to 20 witnesses file testimony. The company discloses the amount of the rate increase it is requesting, and then supports this position with testimony on the individual rate case components. Each witness supports an individual piece of a case -- one witness might be limited to depreciation, another testifies on the appropriate profit level. Another might deal solely with pension costs -– it goes on and on. Usually there's one witness -- it could be the CFO, who files some general testimony describing why the company needs a rate increase.

Public hearings are held, and customers come and tell the ALJ or the commissioners themselves why the company should not be authorized a rate increase. This is just a way for the state to take the pulse of the public regarding their experience with the utility. If there are service problems, that issue usually comes up at public hearings.

The next step in the process is the cross-examination of the witnesses. Witnesses are sworn in, and there's a court stenographer in the room who is typing or recording every word that is spoken. Several weeks later the commission staff and consumer intervenors file their position through the same type of testimony. And then those witnesses are cross-examined.

Then each party files rebuttal testimony stating why the commission should not adopt the other parties' positions. Then surrebuttal testimony is filed addressing the rebuttal testimony, and this is followed by rejoinder testimony, which addresses the surrebuttal testimony. Then final briefs are submitted containing each party's final supported position. Along the way there may be settlement discussions to see if the parties are willing to come up with a compromise on some or all of the issues in the case. Many ALJs and commissions encourage the settlement process because it depoliticizes ratemaking to some extent, especially if all parties realize that the company really needs a rate increase. But some commissions believe that certain important issues need to be fully adjudicated, maybe for setting precedent for future cases.

Regardless of whether there is a settlement, in most cases the ALJ submits a recommended decision to the commission. Essentially, the ALJ's function is to make it easier for the commission to get through the record in the case. After another month or two, the PSC takes a vote, and then issues a final order. Some commissions discuss a case at length in public and then issue a final order a couple of weeks later. Others circulate a draft decision in private, and then come up with a document that contains each commissioner's signatures. In those instances, a final order is issued at the time the final vote is taken.

The typical rate case is usually decided in nine months to a year after the company files the case, but some commissions take much longer. For instance in Arizona, the Corporation Commission, an elected commission, takes 18-20 months to decide a case -- this has been a problem for Pinnacle West Capital subsidiary Arizona

Public Service, as this is a company that has been one of the fastest growing utilities in recent years.

After a final order is issued, any party is free to ask the commission to reconsider the decision on certain issues, or the party can appeal the decision to the courts. The court process is not a quick one -- a case can take more than a year to make its way through the courts. Sometimes, during an appeal, the commission's initial ruling remains in place, but other times, the ruling is "stayed," meaning that the commission's ruling is not implemented until the issue is decided by the courts.

Revenue Requirement

In a rate case, the commission is required to review the company's rate case filing and all intervenors' positions and determine what rate change, if any, is appropriate. So, how does the commission determine the outcome of a rate case?

Since the traditional utility regulation formula is based on cost, we need to start with the following formula -- it is essentially a simple income statement:

Revenue - Operating Expenses - Depreciation - Taxes = Net Operating Income

In the next equation, we have isolated revenue on the left side, and renamed it "revenue requirement":

Revenue Requirement = NOI + Operating Expenses + Depreciation + Taxes

In the third variation, we have renamed net operating income (NOI) as the product of rate-of-return and net assets. Since NOI includes the funds necessary to service all of the utility's securities (debt, preferred stock, common shareholders), the NOI must equal the product of your overall rate of return (or cost of capital) and your asset base.

Revenue Requirement = ROR (Net Assets) + Operating Expenses + Depreciation + Taxes

In the fourth iteration, we have renamed assets as "rate base," which is a regulatory term that refers to the company's utility assets, net of depreciation, as determined by the commission, that are "used and useful" in the provision of service to ratepayers.

Revenue Requirement = ROR (Rate Base) + Operating Expenses + Depreciation + Taxes

The above equations show you how a commission calculates a company's total revenue requirement, but now we need see how the commission determines what rate change is needed, so that the company can achieve its total revenue requirement. In simple terms, the PSC reviews the company's revenue and prudent costs, and considers the resulting earnings. If the earnings are determined to be inadequate, a rate increase is authorized. However, if earnings are determined to be too high, a rate reduction is ordered.

The following equation is the typical rate case formula, and it is the basic rate change calculation that is used in every rate case. This formula produces the rate change that is required:

Rate of Return*
x ***Rate Base****
Required NOI
\- ***NOI Under Current Rates****
NOI Deficiency
x *Tax Factor*
Rate Adjustment

*Rate Case Variable

The formula starts with the required "rate of return" (ROR), which is the return that the company should have an opportunity to earn to service all of its financial securities. This is considered to the firm's overall cost of capital.

Next is the "rate base," which includes all prudent capital investment, net of depreciation -- essentially the asset base upon which the company should be allowed to earn a full return. And, as we saw from the previous equation, the product of the ROR and the rate base gives you the required NOI. From this result, the commission subtracts the NOI that the company is currently earning or is projected to earn. In other words, without a rate case, what NOI will current rates produce? Subtracting that number from the Required NOI gives you what we call the NOI deficiency.

The NOI deficiency is then grossed up for income taxes to yield the rate adjustment that is required. You must gross up the NOI deficiency because customers' rates are revenue, which of course is a pre-tax number.
Notice that three variables in this formula have asterisks. These are the three variables that are essentially the critical issues in each and every rate case. Any disallowance that the commission makes to the company-proposed rate increase is always in one of these three areas – rate of return, rate base, or net operating income.

Rate of Return
In order to calculate (or estimate) a company's ROR, you start with the firm's capital structure. Utilities sometimes support a capital structure with a greater equity component because equity is always assigned the highest cost, and therefore the overall return would be higher, leading to a larger rate increase. A typical rate case capital structure and cost rates are shown below.

	Capitalization Weight (%)	Cost Rate (%)	Weighted Cost (%)
Long-Term Debt	51	6.50	3.32
Preferred Stock	4	5.00	0.20
Common Equity	45	11.00	4.95
	100		8.47

In a rate case, the cost of debt, 6.5% in the table above, is the "embedded" cost of debt, usually an average of the cost of the debt issues that the company has outstanding. It is not the current yield – it is the embedded cost which reflects the bonds' coupon payments. This issue is usually straightforward. The same methodology applies to the cost of preferred stock.

The return on equity, however, is probably the most widely litigated issue in a rate case. There is no stated return that an equity holder is promised, and of course there is no stated interest rate. The only stated number is the company's dividend, and that is not considered a contractual part of a shareholder's return. Then there's the growth piece of the return, and of course no one can predict with any certainty what that should be.

In a rate case, the company hires a witness, usually an outside financial consultant, who provides "evidence" regarding the level of the return on equity required by investors. And, the commission staff and the intervenors provide their own witnesses. And these witnesses usually use very similar methodologies to estimate the ROE, but they usually come up with very different results. For instance, in today's environment, company witness' seem to support an ROE ranging from 11% to 11.5%, while the Staff witness' come up with a 9.5% to 10.5% equity return, and the consumer advocate witness can be counted on to support a lower number. And they all use the same methods.

The most common ROE method used in utility rate cases is the discounted cash flow (DCF) model, or the Gordon Model:

Required ROE = Dividend/Market Price + Growth

On the face of it, the DCF is a simple model -- it looks like all you have to do is plug in a few numbers and you have your answer. First you plug in the company's dividend, divide that by the current stock price, and add a growth factor to the dividend yield. However, the parties argue about the appropriate dividend -- is it today's dividend rate or tomorrow's? What stock price is appropriate to use -- today's price? Or an average price of some representative period of time? And then there is the growth rate; should it be the growth rate of dividends, book value, or earnings? And should it be historical growth or expected growth? Basically, with all of these variations, a witness can mold the DCF to arrive at any desired result.

The next most popular method for determining the required ROE in utility rate cases is the Capital Asset Pricing Model (CAPM):

Required ROE = Risk-Free Rate + Market Return Premium (Beta)

This model seems to involve less guesswork, but still the results can vary. The CAPM starts with a risk-free rate (usually a Treasury rate) and then a risk premium is added that is based either on the specific company in question, or the entire utility industry. To estimate the appropriate risk premium, you use a general stock market risk premium and multiply that premium by "Beta," which is a sensitivity factor for stock in question or the relevant industry. By definition, the beta for the entire stock market is one, and for the utility industry, which tends to have below average price variability, the beta has historically been below one.

Like the DCF, the CAPM has its own set of variables that you can mold to arrive at a desired result. Is it appropriate to use a short-term Treasury rate or a long-term rate? What is the historical market premium? Should the commission measure that over five years or 20 years?

A third method is "Comparable Earnings." The rate-of-return witness selects a group of companies that have similar risk characteristics to the company in question. Then the witness performs a DCF or CAPM for each company in the group, and comes up with an average ROE. Usually the company witness selects a group of companies that have greater risk characteristics than their company, and the commission staff and the consumer advocate witnesses select a group of companies that have lower risk characteristics. Many times you have to use a comparative method like this, because the utility company may be a subsidiary of a very large holding company, and there is no stock price for the subsidiary that can be plugged into the DCF formula.

Bottom line: there is no correct way to calculate or estimate the appropriate ROE. Another issue that factors into the decision is whether the utility is an electric distribution company with no regulated generation. Commissions consider these companies as lower-risk entities, and are authorizing slightly lower ROE levels. Also, commissions may authorize a slightly lower ROE for companies that use a decoupling mechanism, which allows a utility to recover revenues that may have been lost due to customers' conservation efforts. Fully integrated electric companies, those with generation, are sometimes considered higher-risk companies, and have been authorized slightly higher ROEs.

Rate Base

The second rate case variable is the company’s rate base, which again is the asset base from which the utility provides electric service. The largest portion of an electric company's rate base is made up of the firm’s net plant -- generation, transmission, and distribution, assuming that the company is still vertically integrated and still has generation. In some states, e.g., New York, Connecticut, Massachusetts, the utilities sold off their electric generation plants a few years ago to independent, non-utility companies -- so, for those utilities, their rate bases would include the delivery wires, but no generation.

Allowing construction work in progress (CWIP) in rate base was a controversial issue in the 1970's and 1980’s when huge nuclear construction projects were commonplace, but the issue is again receiving attention. Including CWIP in rate base allows the utility to collect a cash return on the asset under construction prior to its completion. If the CWIP is not included in rate base, the utility records a non-cash regulatory asset known as "allowance for funds used during construction" (AFUDC), which is equal to the assumed return on the CWIP. With AFUDC, during construction, earnings remain whole because the company is booking a non-cash additive as earnings, but cash flow takes a hit. Once the plant is used and useful for utility service, the accumulated AFUDC is included in rate base as plant in service. Several states have statutes that prohibit the inclusion of CWIP in rate base.

Rate base also includes inventories, cash working capital, regulatory assets, and an offset for deferred taxes. Essentially, deferred taxes are tax balances that the company has collected from its ratepayers, but have not yet paid to the government. Commissions generally treat these balances as a cost-free source of capital for the company, and logically remove these balances from rate base.
Like rate of return, rate base is fairly controversial. What period should the commission use to measure rate base? Should it be a specific historical date? Should it be a date in the future that contains projections? (Using projections generally produces a higher rate base). Does the commission include CWIP in rate base? Does it permit working capital in rate base?

Net Operating Income

The third rate case variable is the company’s NOI under current rates. The commission has to project what the company’s NOI would be assuming it did not file a case.

It should be noted that a rate case is always based on a “test year,” which is a 12-month period that's used to measure revenues and expenses to come up with the NOI that the company would earn during that period without any change in rates. Sometimes the test year is forward looking, but most times the test year is an historical period. From a utility's viewpoint, a forward-looking test year is better, because looking forward usually brings higher costs, and if the commission recognizes these higher costs, your rate increase will be greater.

In rate case filings, the utility usually supports an NOI that is quite a bit lower than the NOI projected by the Staff and the consumer advocate. Referring back to the rate case formula, a lower NOI under current rates produces a greater NOI deficiency, which in turn produces a greater rate increase. But as with the first two variables, rate of return and rate base, there are a lot of moving parts.
The NOI components that are discussed in rate cases include sales forecasts. To determine a sales forecast, weather issues are reviewed. What is normal weather? An electric company might say that last year's cold summer was normal, and the consumer group might say that the hot summer from two years ago is the norm. And gas companies might say that last year's warm winter was the norm, in an effort to minimize the test year revenues that goes into the NOI calculation. Conservation issues have also come into play, as a utility might testify that its revenues have been reduced by customers' conservation activities. The state of local economy may also figure into the discussion of sales forecasts. The company would say the economy is weak, while the consumer advocate might be more optimistic.

The other part of NOI is the company's expenses, and this is very controversial. How much has been or is going to be spent on fuel and purchased power? How does the company's level of wages compare to other companies? Are executives receiving excessive bonuses? Are the company's depreciation schedules appropriate given the useful lives of the equipment? It needs to be noted that not all expense disallowances in rate cases will affect a utility's earnings in the coming year. If the company is spending money on something that the commission has disallowed for ratemaking purposes, the company's earnings will clearly suffer; however, if the commission disallows accelerated depreciation, the company can adjust its amortization schedules to reflect what was approved by the commission, and therefore, there would be no earnings effect from the commission's action. Cash flow might suffer, but earnings should remain whole.

Rate Case Example

The table below shows the rate case formula as it applies to a rate proceeding for New York State Electric and Gas (NYSEG) that was filed in September 2005 and decided in August 2006.

NYSEG (Case No. 05-E-1222), Decided August 23, 2006

	NYSEG Filing	PSC Ruling	Approximate Difference
Rate of Return*	7.88%	7.18%	$17
x ***Rate Base*** *(millions)* *	$1,513.6	$1,459.9	$7
Required NOI	$119.3	$104.8	
- ***NOI Under Current Rates*** *	$85.2	$126.2	$70
NOI Deficiency	$34.1	-$21.4	
x *Tax Factor*	1.7	1.7	
Rate Adjustment	$58.0	-$36.3	$94

Source: Regulatory Research Associates/SNL Energy — *Rate Case Variable

NYSEG was supporting a $58 million electric rate increase based upon a 7.88% return on a rate base valued at more than $1.5 billion. Instead of authorizing the company its requested rate increase, the New York Public Service Commission (PSC) ordered NYSEG to reduce its electric rates by $36.3 million. As you can see from this comparison, adjustments were made to each of the three rate case variables. The authorized rate of return is lower than that requested, the adopted rate base is lower, and the net operating income under current rates is higher. Each of these adjustments eats away at the rate increase requested by the company.

At Regulatory Research Associates, we analyze the individual rate case adjustments -- in this case, the adjustments totaled $94.3 million, which is the difference between the $58 million increase requested by NYSEG and the $36.3 million reduction ordered by the PSC. Through a variety of formulas, we determined that about $17 million of the total difference stemmed from the PSC's decision to adopt a lower rate of return that than supported by the company. Regarding rate of return, we considered the Commission's decision negative because the authorized ROE, 9.55%, was very low by industry standards, and because of certain adjustments to the capital structure, the company would probably not have been able to earn even that very low return.

There was $7 million of difference attributable to various reductions to rate base, most of which came from the PSC's decision to maintain a deferred balance of funds from a previous rate case that was held for future ratepayer benefit. These are funds that the company continues to hold. Therefore, this disallowance should not have a negative effect on the company.

NOI adjustments account for the remaining $70 million of the total revenue requirement difference. About $11 million of this amount came in the form of a tax expense difference associated with the capital structure change; about $23 million was due to an adjustment in depreciation rates -- the PSC used whole-life rather than remaining life -- so cash flow suffers here, but not earnings. A test period sales adjustment accounted for $4 million, as the PSC used a higher sales growth estimate than what the company proposed. There was also an $8 million difference related to pension expense -- apparently the Commission used a different discount rate to measure pension expense. About $7 million of NOI difference came from the disallowance of management incentive compensation. Remember that just because the PSC disallowed this expense, it does not mean that the company cannot make that expense. It only means that if that expense is incurred, there is no recovery from customers, and the company’s earned return will be reduced. Bottom line: this was a negative decision for NYSEG.

Adjustment Clauses

In addition to the traditional rate case, most commissions make use of adjustment clauses that allow companies to adjust rates for certain items outside of a rate case. Adjustment clauses for fuel costs are the most common. These clauses became popular back in the 1970’s during the oil embargo, when fuel prices skyrocketed and the utilities had no easy way to recover the increased costs. The companies could not file rate cases fast enough, so the commissions started using these types of clauses, which isolate this specific expense.

The use of adjustment clauses tend to shift the risk associated with rising fuel costs from shareholders to customers, because the adjustment clause allows the utility to recover these higher costs fairly quickly, without the complications associated with a full rate case filing. A number of states also use this type of mechanism to allow recovery of environmental compliance costs or conservation costs or to pass through to customers any revenues that the company may receive from selling excess power or excess gas pipeline capacity in the open market.

Appendix E – *Pipelines & Utilities, IFRS Considerations* article

A10. The article below titled *Pipelines & Utilities, IFRS Considerations* was included in the Weekly Credit Edge published by BMO Capital Markets Research on 22 March 2010. [Reproduced with permission.]

Pipelines & Utilities
IFRS Considerations

Over the last few years, there has been considerable discussion about International Financial Reporting Standards (IFRS) and what the adoption of these standards means for Canadian regulated utility and pipeline companies. As the January 1, 2011, deadline draws near, companies in our coverage universe have accelerated the level of disclosures regarding the potential impact of IFRS on their financial statements. While there are several differences between IFRS and Canadian GAAP accounting (Appendix A), we believe the lack of guidance on the recognition and measurement of regulatory assets and liabilities will have the most material consequence on reported financial statements, given the potential for a significant one-time adjustment to equity in the year of adoption and more volatile earnings going forward.

However, the risk of a significant one-time adjustment to equity appears to have diminished, following the release of an exposure draft *(Rate-regulated Activities)*on July 23, 2009, by the International Accounting Standards Board (IASB) that proposes to set out criteria for the recognition and measurement of regulatory assets and liabilities arising from cost of service regulation. We are encouraged by this development but note that the exposure draft has set out more rigid rules for the recognition of regulatory assets and liabilities than under Canadian GAAP. For example, it is our understanding that incentive-based regulation is not currently within the scope of the exposure draft. Therefore, one-time adjustments to equity may still be required, but the adjustments may not be as large as initially expected.

We also believe the following points about the exposure draft are important:

- The assets or liabilities arising from rate-regulated operations will be measured at their expected present value at initial recognition as well as at each subsequent reporting period, using a probability-weighted cash flow approach. Currently, rate-regulated entities capitalize the regulatory asset at 100% of the incurred cost, as long as future recovery in rates is probable;
- Regulatory assets will be assessed for impairment when the company concludes that it is not reasonable to assume that it will be able to collect sufficient revenues from its customers to recover its costs, pursuant to IAS 36 *Impairment of Assets*;
- Restatement of property, plant, and equipment is not required at initial adoption for amounts that would qualify for recognition as regulatory assets pursuant to the exposure draft. Deemed cost will be used;
- Regulatory assets and liabilities will be presented separately from other assets and liabilities; and
- Comments on the exposure draft were submitted for consideration to the IASB up until November 20, 2009. The IASB initially planned to issue a final standard in June 2010, but the date has been pushed back to Q2/11- H2/11.

Revisiting the Debt Ratio

Although accounting guidance appears to have emerged for the recognition and measurement of regulatory assets and liabilities, a one-time adjustment to equity may still be required, given the more rigid definition of regulatory asset or liability per the exposure draft. The improvement or decline in debt-to-capital ratios arising from the change over to IFRS will likely be dependant on whether the company has a net regulatory asset or liability, among other factors. As set out in Table 1, companies in our coverage universe reported total net regulatory assets and liabilities of approximately $8.5 billion and $6.1 billion, respectively, as at the end of fiscal 2009. Entities that are likely most at risk of a potential increase in the debt-to-capitalization ratio are those with material net regulatory asset balances. These include: Newfoundland Power, Terasen Gas Inc., and GazMetro. Entities with material net regulatory liability accounts, such as Enbridge Gas Distribution, Toronto Hydro Corporation, and Fortis Alberta, may see an improvement in their debt-to-capitalization ratios.

Table 1: Net Regulatory Balance as a % of Total Capital

	Regulatory Assets	Regulatory Liability	Net Regulatory Asset (Liability)	As a % of Total Capital
Pipelines				
Alliance Pipeline	$182.9	$4.6	$178.3	8.59%
Enbridge Inc.	$1,411.0	$1,038.0	$373.0	1.68%
Enbridge Pipelines	$503.0	$2.0	$501.0	4.75%
TransCanada	$1,745.0	$416.0	$1,329.0	3.56%
Westcoast Energy (1)	$919.0	$741.0	$178.0	2.14%
Total Pipelines	***$4,760.9***	***$2,201.6***	***$2,559.3***	***3.18%***
Utilities				
AltaLink LP	$3.8	$135.5	($131.7)	-8.86%
CU Inc.	$445.0	$476.4	($31.4)	-0.60%
Enbridge Gas	$304.7	$1,168.6	($863.9)	-17.20%
EPCOR Utilities	$28.0	$10.0	$18.0	0.39%
FortisAlberta	$98.5	$272.2	($173.8)	-10.33%
FortisBC	$104.2	$4.4	$99.8	10.25%
Gaz Metro (1)	$347.9	$48.0	$299.9	10.99%
Hydro One	$1,105.0	$604.0	$501.0	4.06%
Newfoundland Power	$208.8	$78.6	$130.2	14.98%
Nova Scotia Power	$244.2	$25.0	$219.2	7.51%
Terasen Gas Inc.	$389.8	$79.2	$310.6	12.29%
Toronto Hydro	$68.2	$308.6	($240.4)	-10.88%
Union Gas (1)	$351.0	$659.0	($308.0)	-8.30%
Total Utilities	***$3,699.1***	***$3,869.6***	***($170.5)***	***-0.37%***
Total	**$8,460.0**	**$6,071.2**	**$2,388.8**	**1.88%**

Note: (1) As at September 30, 2009.
Source: Company Reports

We believe Canadian pipeline and utility companies are currently reviewing their trust indenture agreements and recalculating financial ratios under various scenarios to determine whether any financial covenants will be breached when they transition over to the new accounting standard. Given that Canadian utility and pipeline companies generally have maintained conservative balance sheets consistent with regulatory-approved debt ratios ranging from 55–65%, there is likely ample room before maximum borrowing levels under the indentures are reached. Table 2 highlights each company's regulated debt ratio compared to the limitations on indebtedness under the trust indentures.

Table 2: Regulated Debt Ratios vs. Covenant Limitations on Indebtedness

Issuer	Regulated Debt Ratio (%)	Covenant Threshold (%)
Pipelines		
Alliance Pipeline	70.0%	(1)
Enbridge Inc./Enbridge Pipelines	55.0% (2)	75.0%
TransCanada PipeLines	60.0-65.0% (3)	75.0%
Westcoast Energy Inc.	64.0% (4)	75.0%
Utilities		
AltaLink, L.P.	64.0%	75.0%
CU Inc.	61.0-64.0% (5)	75.0%
Enbridge Gas Distribution Inc.	64.0%	(6)
EPCOR Utilities Inc.	59.0-63.0% (7)	70.0%
FortisAlberta Inc.	59.0%	75.0%
FortisBC Inc.	60.0%	75.0%
Gaz Metro Inc.	54.0%	65.0% (8)
Hydro One Inc.	60.0%	75.0%
Newfoundland Power Inc.	55.0%	65.0%
Nova Scotia Power Inc.	62.5%	75.0%
Terasen Gas Inc.	60.0%	75.0%
Toronto Hydro Corporation	60.0%	75.0%
Union Gas Ltd.	64.0%	75.0%

Note:

(1) Max borrowing of no more than US$10.0 million of 70% of the rate base for senior debt; 85% for total outstanding indebtedness

(2) Enbridge System, Alberta Clipper (Canada), Southern Access (Canada)

(3) Canadian Mainline - 60%; Alberta System - 65%

(4) BC Pipeline (Transmission) and Union Gas

(5) ATCO Gas and ATCO Electric (Distribution) - 61%; ATCO Electric (Transmission) - 64%

(6) Cannot issue additional debt unless consolidated earnings at least 2x the annual interest after factoring in the issue of such additional debt

(7) Distribution - 59%; Transmission - 63%

(8) Restricted from paying distributions if the ratio of long-term debt to capital were to increase to greater than 75%.

Source: Company Reports, Trust Indenture Agreements

In our opinion, while IFRS adoption will likely not pose any indenture-related issues, we note that on July 30, 2009, TransCanada Pipelines proposed a set of amendments to its 1970 and 1993 trust indentures, one of which was directly in response to IFRS. The proposal involved amending the definition of "Consolidated Equity" to exclude any transitional amounts that would arise as a result of the adoption of IFRS. If the amendment were to be approved, this would effectively allow TransCanada to be neutralized from any positive or negative impact on financial ratios directly stemming from IFRS conversion. While TransCanada did not quantify the impact IFRS would have on its financial position and future results, this initiative suggests that IFRS adoption could have the potential to negatively impact a company's financial flexibility and future financing, strategic, and operating decisions. Moreover, we believe the impact on financial ratios due to IFRS adoption may be more pronounced for entities with greater exposure to non-regulated operations.

Looking to the European Experience for Guidance on Credit Ratings

On October 28, 2004, Moody's released a special comment entitled, "The Impact of IFRS on the Credit Ratings of European Corporates", in which it identified the significant changes that it anticipates will have to be made to financial statements for publicly traded European companies adopting IFRS on January 1, 2005. The agency also examined the expected impact on key credit metrics such as EBIT, interest expense, cash flow from operations, and debt. In its analysis, the rating agency identified several factors that could potentially impact the credit rating of an individual issuer due to IFRS:

(i) disclosure of risk or financial characteristics not previously evident from the reporting under local GAAP;
(ii) market perceptions changing to the detriment of the issuer;
(iii) restrictive banking or other covenants breached when the numbers are restated;
(iv) adverse regulatory behaviour in response to the new financial metrics; and
(v) change in the behavior of the issuer, in terms of managing risk, remunerating staff, or issuing particular types of financial instruments.

Despite highlighting these risks, Moody's noted that it would be surprised if the above factors manifested themselves to a material degree and that it believed the impact on ratings will be limited. Out of the 20 most important accounting changes identified by Moody's, 14 will have no impact on cash flow from operations, and three out of the remaining six changes would be overridden by Moody's financial statement adjustment methodologies. Moody's reiterated that its rating process would continue to be focused on underlying economics and strong emphasis on cash flow-based measures and metrics.

On August 11, 2005, S&P released a comment entitled, "No Major IFRS Issues So Far for Top European Utilities", in which the agency reported that the release of preliminary financial information according to IFRS (pro forma IFRS 2004 figures and Q1 or half-year 2005 results) has not had an impact on ratings so far. The agency did note, however that it remains to be seen whether IFRS will have an impact on utility future financial or operating decisions, such as funding mix, dividend policies, hedging policies, or investments. In a follow-up S&P report dated January 23,2007, "IFRS After Transition: What's in Store for Standard& Poor's Credit Analysis", the agency indicated that the "transition to IFRS has been remarkably smooth for European companies" and that none of the accounting changes arising from IFRS adoption single-handedly caused a change in credit ratings.

Therefore, the limited impact on European corporate credit ratings after IFRS transition suggests that there will likely be no major credit ratings issues for the entities in our coverage universe. We would be surprised to see rating agencies swiftly move to alter fundamental opinions. Accounting standard changes should not result in material changes to credit quality. To the extent disclosures are provided, we believe ratings agencies will continue their long-standing practice of adjusting financial statements when calculating financial ratios and base credit ratings on these ratios. We also expect rating agencies to continue to focus their attention on cash flow-based metrics and underlying economics.

Disclosures Expected to Be Enhanced

We understand that the upcoming replacement of Canadian GAAP with IFRS may have been driven by investor demand for improved transparency and a higher degree of comparability in the financial statements, especially in the context of a more integrated global capital market.

IFRS may also better portray a company's underlying economic reality, given its marked-to-market oriented approach. We anticipate a significant increase in disclosure arising from the adoption of IFRS. For example, more extensive disclosures regarding the reconciliation of each category of regulatory assets and liabilities from the beginning of the period to the end may be required. The enhanced financial disclosures, in addition to information systems upgrades, and staff training will likely result in an increase in operating expenses. We expect that any increase in operating costs will be recoverable from ratepayers