KPMG Report to the Ontario Energy Board

Report on the Transition to International Financial Reporting Standards

March 4, 2009

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Preface to Report on the Transition to IFRS

Much has been written about the impending change in the financial reporting framework in Canada. The Canadian Accounting Standards Board has determined that all publicly accountable enterprises will adopt IFRS as the source of generally accepted accounting principles to be used in Canada for financial reporting periods commencing on or after January 1, 2011. This change is profound and it will have impacts on preparers, users and auditors.

This report identifies the major impacts that will need to be dealt with by the OEB, the utilities subject to regulation by the OEB, and other interested parties. It would be ideal if definitive answers to all of the questions that will arise could be developed. However, that is not possible as we are dealing with a moving target. IFRS is no more static than Canadian or U.S. GAAP has been over the years. It is an evolving set of standards and we anticipate that there will be new or modified standards in place by the Canadian transition date and shortly thereafter.

Another key factor to acknowledge is that IFRS is relatively new and while it is considered to be principles based as opposed to rules based, there is a growing body of interpretive guidance. Not all of that interpretive guidance is consistent. Further, we are unable to predict how securities regulators will adapt to or interpret the new framework. Another feature of the IFRS framework is that it tends to allow more accounting choices than are available under current Canadian GAAP. That is expected to result in perhaps less consistency in some areas of financial reporting. One of the areas where entities will be afforded more leeway is in the use of fair value accounting. Another will be the manner in which they transition to IFRS.

As we will explain in more detail, KPMG is not advocating positions in this report. We hope to be able to provide the information to help enable the OEB, the utilities and other interested parties to develop their positions. But to do this, there have to be some ground-rules to help frame the discussion:

1. We have been advised we can assume that the OEB will continue to use some form of cost based ratemaking. This is presumed to include incentive regulation;
2. We have assumed that the utilities will have a free choice in choosing how they will adopt IFRS for their general purpose financial statements;

3. We recognize that utilities will likely need to do some reconciliation work to link their general purpose financial statements to the information used by the OEB in its regulatory capacity. We accept that the process of reconciling differences between the IFRS framework and the regulatory framework will result in more administrative costs. We are unable to estimate the magnitude of such costs or how they might be handled as this is between the OEB and its stakeholders. We will however attempt to point out where the likelihood of significant reconciling items exists, which may require utilities to establish additional internal processes and controls;

4. We recognize that the OEB considers many factors in setting rates. We believe that using IFRS as the foundation for determining costs, even in an historical cost of service methodology, would result in at least a change in the timing of when those costs would be recognized in a number of situations. We will attempt to point out what the differences will be but, at this stage, it is nearly impossible to try to estimate the extent of the impacts. We will try to at least identify whether costs would be recognized sooner or later, although even that will be difficult in some cases. Where it is, we will point that out; and

5. We believe that there will be a tendency in the discussion on IFRS to focus on individual items in isolation but we must caution that this approach has pitfalls. Many of the decisions that will be made are closely linked and some decisions will likely preclude a number of other decisions and possible outcomes. The use of regulatory deferral accounts is one example. A decision to continue to use regulatory deferrals for regulatory purposes regardless of what is allowed under IFRS would have implications in virtually all areas.

Executive Summary

From January 1 2011, some, and perhaps all, utilities regulated by the Board will prepare their general purpose financial statements in accordance with IFRS. There are a number of accounting differences between IFRS and current Canadian Generally Accepted Accounting Principles ("CGAAP") which could have material impacts on the accounting values reported in these financial statements.

In many areas, the accounting values reported in financial statements are used as a reference point when the Board determines just and reasonable rates for regulated services. As a minimum, therefore, the Board must be aware of and understand the implications of the transition to IFRS on all relevant stakeholders and assess whether any changes are required to current rate setting methodologies to address issues that may arise.

This report highlights the major potential impacts of the transition to IFRS from the perspectives of rate payers, regulated utilities and the rate making process. Inevitably at this relatively early stage of the transition we are unable to quantify the financial impacts of such changes; however, it is clear that the impacts may be significant. The impacts can be grouped into four types as follows:

1 Transition adjustments

For financial statement purposes, the transition to IFRS will result in adjustments to the utility's opening retained earnings. The impact, if any, of these adjustments on future rates will need to be addressed.

2 Possible impacts on future rates

Changes to the recorded amounts of existing and future assets and liabilities as a consequence of new IFRS requirements have the potential to change future rates. Certainly the timing of recognition of certain transactions under IFRS will change. This could give rise to short-term volatility in rates and/or reported earnings depending on whether and how smoothing mechanisms, such as deferral accounts are used.

3 Additional costs

A project of such significance will result in additional costs. Such costs will arise in connection with the conversion itself and may include additional internal resources, external consulting and IT systems costs. In addition, it is possible that on-going compliance costs will increase. This may result from additional reconciliation and assurance requirements. The question of who should bear such costs will need to be addressed.

4 New reporting requirements

General purpose financial statements prepared under IFRS will be different to those prepared under CGAAP. Transactions will be recognised in different time periods; will be measured differently and will be reported differently. There may be a need for additional information to allow the Board to determine fair and reasonable rates. Furthermore, certain IFRS accounting policy choices may be unacceptable to a regulator as a basis of setting rates. Such items may need to be addressed.

Inevitably the means of addressing these issues will emerge from a process of discussion between affected parties.

Introduction

A. Background

During February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed the requirement for publicly accountable enterprises ("PAEs") to adopt IFRS for financial reporting periods commencing on or after January 1, 2011. In addition, the Public Sector Accounting Board ("PSAB") directed government business enterprises and government business-type organizations to adopt IFRS in the same time frame (although this is being re-examined – refer Section 6.1(c)). It is currently expected that most entities that are rate-regulated by the Ontario Energy Board ("the OEB" or "the Board") will therefore be required to adopt IFRS. The Board has committed to work with the entities that it regulates to facilitate a smooth transition to IFRS.

B. Purpose of this report

The purpose of this report is to provide independent analysis of the matters identified on the Board's List of Issues to be considered in the Board's Consultation on IFRS. This report identifies:

- the accounting differences that will arise upon transition to IFRS;
- the range of alternatives available to address the accounting differences that have been identified; and
- the implications on rate-making of each of the alternatives for rate payers, regulated utilities ("utilities") and the rate making process.

The preparers of this report also sought to identify and comment on the IFRS conversion experience of other regulatory jurisdictions that are similar to OEB.

C. Limitations on this report

This report should only be used for the purpose set out above.

In particular, the following matters have been specifically excluded from the scope of this report:

a) Recommendations by KPMG on preferred alternatives. Although the report discusses the implications of each particular alternative on the various stakeholder groups, KPMG does not take any positions or make recommendations on any of the options identified in this report. Decisions by the Board on preferred options will depend on how it weighs various decision-making criteria. Such decisions will also be guided by, and evaluated against, principles that may be developed as part of the Board Consultation process;

b) Discussion of changes to filing requirements and rate setting methodologies that are not driven by the adoption of IFRS; and

c) Discussion of the financial risk profile of utilities, and how the adoption of IFRS may affect that risk profile.

This report specifically addresses only those matters identified on the Board's List of Issues. As certain accounting differences can only be identified by detailed review of transactions, contracts and other underlying documentation at the respective utilities, there is no guarantee that all accounting differences will be discussed in this report.

The following should also be noted:

a) The analysis in this report focuses on the effects of the adoption of IFRS on regulatory accounting and rate making. Matters relating to the effect of the adoption of IFRS on the general purpose financial statements of a utility have not been considered in detail in this report;

b) Canadian GAAP and IFRS standards and applied interpretations are subject to revision by the respective authoritative accounting bodies in Canada and the International Accounting Standards Board ("IASB") respectively. The information provided in this report is based on KPMG's current understanding of standards and interpretations issued as at 27 February 2009, and may change materially in response to subsequent changes or revisions. Also, certain of the KPMG views expressed in this report may not necessarily be the current views of other accounting firms.

D. Report Outline

The remainder of the report is organized as follows:

- **Section A** analyses the impact of the transition to IFRS of each of the matters on the Board's List of Issues. For ease of reference in using this report, we have maintained the same issue numbers as those on the Board's List of Issues.

  We have not, however, addressed the matters set out in Section B (issue 1.1 Principles) of the Board's List of Issues as these matters will be separately addressed as part of the Board Consultation process. We have therefore not used issue reference number 1 in this report.

  In addition, where possible, we have discussed item 7.1 on the Board's List of Issues (which relates to the direction and estimated magnitude of rate impacts created by establishing rates on the basis of various IFRS accounting options) within the various Sections dealing with the related accounting issues. Therefore, we have not used issue reference number 7.1 in this report.

- **Section B** summarizes the process followed in order to identify regulatory jurisdictions similar to Ontario, as well as the results of our research;

- **Appendix A** sets out the glossary of terms and acronyms used in this report; and

- **Appendix B** contains a copy of the IASB work plan as at 25 January 2009.

Section A

2. Regulatory Assets and Liabilities

2.1 Use of Deferral and Variance Accounts

This section addresses the question:

"Should the Board continue to use deferral and variance accounts in the event that they are not recognized under IFRS?"

Utilities in Ontario currently use deferral and variance accounts for certain costs that are treated as a pass-through to consumers. Examples include:

- Electricity distributors use Retail Settlement Variance Accounts ("RSVA's") to capture differences between revenues and expenses relating to commodity costs, wholesale market charges, and transmission costs. Utilities implement retail rates that are forecast to recover these costs, and then use variance accounts to capture differences between the associated revenues and expenses.
- Deferral accounts are also used to capture a designated share of differences between expected and actual income tax expenses that arise from legislative changes, such as changes in income tax rates.
- Deferral accounts have been used to track certain costs associated with utility investments to address market changes. Thus, electricity distributors accumulated costs associated with the transition to a competitive retail market as a regulatory asset. Similarly, some costs associated with the implementation of smart meters are now also accumulated in regulatory asset accounts.

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Deferral and variance accounts are recognized in the general purpose financial statements of utilities and described as regulatory assets or regulatory liabilities. Revenues and expenses are adjusted to reflect the regulatory asset or regulatory liability that has been recorded. Carrying charges on these accounts are recorded as interest revenue or expense.

Prior to January 1, 2009, there was an exemption under CGAAP for rate regulated entities from the application of generally accepted accounting principles set out in CICA Handbook Section 1100 to the recognition and measurement of assets and liabilities arising from rate regulation. For example, this exemption allowed such entities to treat deferral and variance accounts as assets and liabilities. The exemption was removed for fiscal years beginning on or after January 1, 2009. Commencing in 2009, utilities will have to apply generally accepted accounting principles and definitions set out in the CICA Handbook. The effect of this change in CGAAP is as yet uncertain as discussed in Section 6.1(d). For purposes of the analysis below, however, it has been assumed that regulatory assets and liabilities will continue to be recognized under CGAAP up until the date of transition to IFRS.

The balances in the deferral and variance accounts are reported to the Board on a quarterly basis by the utilities and annually within audited general purpose financial statements. Periodically, these accounts are reviewed by the Board and rates are adjusted to effectively recover accounts in an asset position or repay accounts in a liability position. The Board determines the period of time over which these accounts are recovered or repaid.

ii. Requirement under IFRS

The economic effect of rate regulation is generally not recognised under IFRS. Based on current practice and interpretation, it is generally expected that deferral and variance accounts would not be recognized as assets and liabilities under the current requirements of IFRS. The manner in which a deferral account is established or authorized would not impact the accounting for the deferral account under IFRS. We note, however that the IASB has put regulated accounting on its active agenda. For further discussion refer to Section 6.1(b) of this report.

iii. Summary of the accounting difference that will exist

Deferral and variance accounts are currently not expected to be recorded as assets and liabilities in IFRS general purpose financial statements. As a result, revenues, costs and expenses that currently would be deferred in the deferral and variance accounts would be recorded in accordance with the specific requirements of IFRS, i.e. as revenue, expenses or capital items.

B. Range of alternatives available

i. Alternative 1 – continue to use deferral and variance accounts for rate-making purposes

The Board could choose to continue with the current practice of using deferral and variance accounts for purposes of rate-making. Utilities could continue to report these accounts to the Board on a quarterly basis but these accounts would no longer be included in the audited general purpose financial statements.

ii. Alternative 2 – cease using deferral and variance accounts for rate-making purposes

The Board could choose to cease using deferral and variance accounts for purposes of rate-making and choose to reflect revenues and expenses as recognized under IFRS.

iii. Alternative 3 – use deferral and variance accounts on a modified basis for rate-making purposes

The Board could choose a third alternative where deferral and variance accounts are used but on a basis different from current practice.

C. Implications of the alternatives on rate-making

The three alternatives to the use of deferral and variance accounts described will have different implications for utilities and customers. Ceasing to use deferral and variance accounts would have a significant impact even if such a change was made under CGAAP. If deferral and variance accounts are not used, there are at least two alternatives for rate setting purposes, and these alternatives will have different implications for utilities and customers:

- Utilities can be asked to forecast the amount of the relevant expense and then to absorb the difference between this forecast and the actual expense incurred.

Utility shareholders will be forced to absorb forecast errors. To the extent that forecast errors do not net to zero over time, rates will depart from actual utility costs and customers will either bear more or less than the full cost.

- Rate setting processes can be structured so that costs are immediately passed through to customers. Thus, in the case of commodity costs, for example, customers could be charged the weighted average spot market price during the billing period, rather than rates set in advance for each quarter. This would likely increase the volatility in rates over time. Currently hydro customers who are eligible for the Regulated Price Plan ("RPP") are billed a fixed price for the commodity. The utility then recovers the difference between the fixed price and the weighted average spot market price through the Independent Electricity System Operator ("IESO"). The differences between actual commodity cost and the combined recovery from customer billings are tracked in a variance account at the Ontario Power Authority ("OPA"). Variance amounts are recovered through adjustments to the fixed price charged in future periods.

i. Implications for rate payers

Continued use of deferral and variance accounts for rate-making purposes:

Continued use of deferral and variance accounts would have a limited impact on rate payers since this would not represent a change from current practice. However, as utilities would likely have to maintain these deferral and variance accounts in addition to the information used for general purpose financial statements, the impact on rates would ultimately depend on whether any incremental compliance costs are recovered in rates.

Cease use of deferral and variance accounts for rate-making purposes:

If deferral and variance accounts are not used on a go-forward basis, revenues, costs and expenses would be measured under IFRS. Rates may be set based on forecasts and in turn, the impact to the rate payer will be dependant upon the accuracy of those forecasts. Interestingly, cessation of deferral and variance accounts would have an impact even if CGAAP were the basic measurement model.

In addition, the amounts recorded in deferral and variance accounts at the transition date will need to be considered. Impacts on rate payers will depend on whether such amounts continue to be recovered/refunded through future rate adjustments or not.

Use deferral and variance accounts on a modified basis for rate-making purposes:

The Board would continue to use deferral and variance accounts to influence the level of rates but on a different basis. Changes in the regulatory model would presumably follow due process but all of the implications noted in the first two alternatives will apply.

In summary:

Alternative	Implications for rate payers
Continue to use deferral and variance accounts	▪ Limited impact
Cease to use deferral and variance accounts	▪ Rates would be determined on a basis that is different from current model ▪ Rates would likely be more volatile ▪ Transitional adjustments to be considered
Use deferral and variance accounts on a modified basis	▪ Entirely dependent on how the Board would modify the rate-making process

ii. Implications for utilities

Continued use of deferral and variance accounts for rate-making purposes:

Under IFRS, deferral and variance accounts are not expected to be recorded as assets and liabilities and therefore such accounts are not expected to be maintained for general purpose financial reporting purposes. Utilities would, however, need to maintain these accounts for rate setting purposes. Currently utilities may have as many as 12 to 15 deferral and variance accounts, which are further split into sub accounts by nature of cost (operating, capital, carrying charges). Processes would need to be developed in order to accommodate the differing reporting needs.

If the Board requires reconciliation between general purpose financial statements and financial information reported for rate application purposes, then this would probably lead to additional on-going compliance costs. Presumably, these reconciliations would need to be tracked and maintained. Internal controls over these processes and procedures would need to be developed to ensure that both sets of records are consistent and accurate. Over time such reconciliations potentially become increasingly difficult to do. Furthermore, the need for reconciliations itself weakens the overall credibility of the financial information upon which the regulator is hoping to rely.

In addition, the Board may decide that independent audit assurance over the balances in the deferral and variance accounts is desirable. Therefore, this may result in increased costs which in turn may need to be dealt with in the rate-making process. Utility staff will have to spend time preparing for and responding to any audit requirements, whether external or conducted by the Board itself.

Utilities will have to continue to be knowledgeable about any guidelines and procedures issued by the Board to regulate the use of deferral and variance accounts as they are now required to do. Utility staff will need this expertise on an ongoing basis with regular updates to their knowledge base to work accurately with these accounts for rate setting purposes. However, maintaining such specialist resources on prescribed regulatory accounting within a utility is no different to what occurs today.

Continued use of deferral and variance accounts for rate-making would provide utilities with some predictability about how the rate-making process would impact their business. However, absent regulatory accounting being introduced into IFRS, virtually any possible alternative that maintains the status quo for rate-making will result in more volatility in the utility's reported earnings. Earnings reported in the IFRS general purpose financial statements may not reflect the economic effects of rate regulation. Utilities may therefore choose to provide additional information in such statements to ensure that the impact of rate regulation is understood and that there are no adverse impacts on a utility's access to capital.

Cease use of deferral and variance accounts:

If deferral and variance accounts are not used for rate setting purposes, then there will be no need to maintain or track these variances. Utilities would simply record revenue, expenses and capital following IFRS. This alternative eliminates the need to maintain two sets of records and any resulting reconciliations and internal control impacts as described in alternative 1.

If rates are based on forecasted costs then the risk and uncertainty over full cost recovery lies with the utility. Amounts incurred in excess of or less than the forecast will be absorbed by the utility rather than the customer base with a consequential impact on reported earnings.

In a rate setting structure where costs are immediately passed through to customers, utilities' cash inflows (billings to customers) will more closely match the timing of the utilities' cash outflows (payment of costs). This is different from the process that is currently in place today where deferral and variance accounts are used to record certain mismatches.

If deferral and variance accounts are not continued, then balances in such accounts on transition will need to be considered from the utilities perspective. If such balances are not able to be recovered/refunded by future rate adjustments, then the utility may be subject to a windfall gain (net regulatory liabilities) or loss (net regulatory assets).

Use deferral and variance accounts on a modified basis for rate-making purposes:

Deferral and variance accounts could continue to be used but on a modified basis. The impact on utilities would depend on the modifications made to the rate setting process. This would not likely reduce the record keeping and internal control requirements. Knowledge of technical requirements relating to the deferral and variance accounts would continue, but also at a reduced level. Audit assurance over the balances may be required.

In summary:

Alternative	Implications for utilities
Continue to use deferral and variance accounts	▪ Increased record keeping and internal control requirements ▪ Potential assurance implications
Cease to use deferral and variance accounts	▪ Financial and regulatory reporting are consistent ▪ Introduces more volatility in reported earnings ▪ Amounts on transition may lead to windfall gain/loss
Use deferral and variance accounts on a modified basis	▪ Increased record keeping and internal control requirements ▪ Potential assurance implications ▪ Implications depend on how the process is modified

iii. Implications for the rate-making process

Continued use of deferral and variance accounts for rate-making purposes:

No changes to the rate setting mechanism would be required. Deferral and variance accounts are currently being used and mechanisms to allow settlement of the regulatory accounts are in place. These mechanisms would continue to be required.

The Board may need to determine additional assurance over the deferral and variance accounts. Currently these balances are generally included as assets and liabilities on utilities' audited CGAAP general purpose financial statements and are therefore subject to an independent examination as part of a general purpose financial statement audit. Under IFRS, these balances are not expected to be recognized in the general purpose financial statements. Without a change in Board requirements, balances reported to the Board will no longer be subject to audit. If additional audit assurance is required it may result in additional costs to the utilities and the disposition of those costs would need to be considered.

Utilities would require procedures and guidance for the continuing establishment and maintenance of deferral and variance accounts. Currently this guidance is set out in the Accounting Procedures Handbook ("APH").

Cease use of deferral and variance accounts for rate-making purposes:

If deferral and variance accounts are not used, then any balances recorded in these accounts on transition to IFRS will need to be addressed. In audited general purpose financial statements of the utilities, these account balances will be adjusted against the opening retained earnings. Regulatory liabilities will lead to an increase in retained earnings and regulatory assets will lead to a reduction in retained earnings. The question is how should these amounts be dealt with from a rate-making perspective, i.e. will future rates continue to be adjusted to reflect refund/recovery of such amounts or not.

On a go-forward basis, the Board would need to determine how to set rates based on amounts that are measured and reported under IFRS.

Use deferral and variance accounts on a modified basis for rate-making purposes:

Continuing use of deferral and variances accounts on a modified basis does not eliminate any of the implications noted above.

In summary:

Alternative	Implications for the rate making process
Continue to use deferral and variance accounts	▪ Rate setting status quo is maintained ▪ Additional assurance may be required ▪ Establish and update procedures and guidance for use of deferral and variance accounts
Cease to use deferral and variance accounts	▪ New or revised rate setting mechanism required ▪ Amounts on transition need to be considered
Use deferral and variance accounts on a modified basis	▪ New or revised rate setting mechanism required ▪ Additional assurance may be required ▪ Establish and update procedures and guidance for use of deferral and variance accounts

2.2 Approved Definitions of Deferral and Variance Accounts

This section addresses the following question:

"Should the Board approve definitions for deferral and variance accounts if the Board retains their use for regulatory purposes?"

A. Relevant issue to be addressed

This question is not impacted by the transition to IFRS. We are unable to comment on the implications of approving specific definitions of deferral and variance accounts for regulatory purposes.

We note, however, that it is extremely unlikely that the Board, or any regulator, would be able to establish definitions of the deferral and variance accounts that would meet the criteria currently required under IFRS for utilities to record such amounts as assets/liabilities in general purpose financial statements.

There is a possibility that the IASB will modify IFRS in the future to allow the economic impacts of rate regulation to be reflected in general purpose financial statements. If this occurs, this matter should be re-visited at that time as it is possible that recognition criteria would be set that might motivate the Board to approve definitions for such accounts so that they fit within the IFRS guidelines.

3. Property, Plant and Equipment ("PP&E")

3.1 Opening rate base values at transition to IFRS

This section addresses the following question:

"For the purpose of first-time adoption of IFRS, should the Board require historic cost (NBV) or the IFRS adoption requirements (fair market value or retrospective restatement) to be used as the basis for setting opening rate base values and reporting to the Board?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Currently, the Board requires that utilities report PP&E based on actual costs. Regulatory rates have been set and adjusted over many years in order to allow utilities to recover the costs of providing services to their customers. As a result, the net PP&E value at any point in time represents many years of capitalized costs and applied depreciation policies. This value would have been impacted by many elements, including capitalized burden, borrowing costs, customer contributions, asset retirement obligations, derecognition of disposed assets, and depreciation. Each one of these individual elements and their potential impact is discussed in further detail in Sections 3.3 and 3.4. This Section will focus on the issues and implications of first-time adoption of IFRS on the rate base calculation.

ii. Requirement under IFRS

The IFRS standards related to the initial and on-going measurement and recognition of PP&E differ from the standards currently applied by utilities under CGAAP. As mentioned above, these differences occur in areas such as capitalized burden, borrowing costs, customer contributions, asset retirement obligations, derecognition of disposed assets, and depreciation.

First-time adoption of IFRS generally requires the retrospective restatement of financial statements as of the beginning of the earliest comparative period presented (in this case January 1, 2010); i.e. an entity must restate its reported results "as if"

IFRS accounting policies have always been applied. Recognizing the practical difficulties and costs and benefits of this, the transition standard, IFRS 1, provides certain exemptions and exceptions to this general rule.

In particular, on transition, a utility may elect to measure an item of PP&E at its fair value and use that fair value as its deemed cost at that date. This is a transition election for historical assets only, and does not impact the requirement to record all future assets according to the IFRS standards for PP&E.

IFRS defines fair value as *"the amount for which an asset could be exchanged between knowledgeable, willing parties in an arm's length transaction"*. Fair value is usually determined from market-based evidence by appraisal that is normally undertaken by professional qualified valuers. However, if there is no market-based evidence of fair value because of the specialized nature of the item of PP&E and the item is rarely sold, except as part of a continuing business, an entity may need to estimate fair value using an income or a depreciated replacement cost approach ("DRC").

In applying an income approach, a discounted cash flow (DCF) methodology is generally used. A valuator typically estimates the future net cash flows that can be directly attributed, or allocated on a reasonable and consistent basis, from the continued use and ultimate disposal of the asset. These net cash flows are then present valued at a discount rate that reflects the time value of money as well as the possible variations in the amount and timing of the expected future cash flows.

The depreciated replacement cost method involves estimating the cost of constructing the item of PP&E at current prices and then adjusting the value for factors such as depreciation, service condition of the asset and obsolescence. If using a DRC approach, utilities would also be required to ensure that the resulting value is recoverable given that regulated cash flows may be insufficient to recover a value based on "current costs" rather than actual costs.

Alternatively, a first-time adopter can restate its opening value of PP&E by applying the requirements of IFRS retrospectively i.e. adjust the carrying value of PP&E as at January 1, 2010 for all the changes required in order to comply with IFRS (e.g. capitalization policies, borrowing costs, customer contributions, depreciation policies, etc).

We note also that an additional IFRS 1 exemption has been proposed which would allow rate regulated utilities to use current historical carrying value of assets as deemed cost at the date of transition. The current proposal is that this exemption would apply only if it is impracticable to determine fair value or to restate historical costs for IFRS. The onus is on the entity to demonstrate impracticability. If this exemption is approved, then utilities will be permitted to use carrying value of PPE at the date of transition as the opening value for IFRS. This is a one-time historical exemption, and would have no impact on assets that go into service after the date of transition. The current exposure draft has not yet been approved, and consequently the exemption may not be available. If approved, it could eliminate possible differences arising between the opening book values under IFRS for general purpose financial reporting and the amount of PPE included in rate base should the Board require historical cost NBV to be used. Refer Section 6.1(a) for more details.

iii. Summary of the accounting difference that will exist

As more fully detailed in Sections 3.3 and 3.4, differences exist in accounting for PP&E under IFRS. At most utilities, the current Net Book Value (NBV) of PP&E under CGAAP is unlikely to be the value determined retrospectively in accordance with IFRS. Utilities will have to consider the cumulative effect of these differences, and may have to record adjusting entries.

B. Range of alternatives available

i. Alternative 1 – Require Historical Cost ("NBV")

The Board could choose to require the historic cost (NBV) of assets existing at January 1, 2010 to be used as the basis for setting opening rate base and reporting to the Board. Notwithstanding this policy, however, utilities may still have to restate the value of their assets for financial reporting purposes under IFRS.

ii. Alternative 2 – Retrospective restatement

The Board could choose to require all utilities to retrospectively restate the historical cost of PP&E in accordance with IFRS for rate base purposes.

iii. Alternative 3 – Fair value

The Board could choose to require all utilities to determine the current fair value of their PP&E, and use these values for rate base purposes.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

If the Board were to choose the NBV alternative, then costs as identified in past rate submissions using historical approaches to capitalization would remain intact. As a result, the transition to IFRS would have no impact on the rate base component of the rate calculation for existing assets.

As more fully detailed in Sections 3.3 and 3.4, differences exist in accounting for PP&E under IFRS. If the Board were to require the retrospective restatement of historical PP&E, then utilities would need to re-visit the original amounts capitalized, and to the extent possible, remove (or add back) the amounts included or excluded that differ from the IFRS standards. While it is difficult to be definitive given the inconsistency in capitalization and depreciation policies currently in practice, there is some likelihood that total historical rate base would decrease as compared to the currently determined values. The Board would then need to determine what to do with any difference that arises between the CGAAP historical values and the new IFRS opening values on transition.

If the Board were to choose the fair value alternative, then the Board would need to be aware of the significant and subjective judgments that are often made in estimating fair value. This often results in significant measurement uncertainty, which would impact on rate base. This fair value alternative would also lead to a potential disconnect between the actual cost of the network, and the value being assigned to rate base.

In summary:

Alternative	Implications for rate payers
Historical Cost	▪ Status quo ▪ Rates would remain consistent with prior submissions
Retrospective Restatement	▪ IFRS rate base unlikely to equal existing NBV ▪ Impact of transition difference to be addressed
Fair value	▪ Possible significant differences relative to existing NBV ▪ Subjective judgements and estimates required ▪ Transition differences to be addressed

ii. Implications for utilities

If the Board chooses the NBV alternative, then utilities will use historic costs of existing assets as a basis for their rate submissions. Unless the IFRS exposure draft discussed above is approved, however, utilities will be required to prepare and maintain a separate set of financial records for IFRS reporting purposes. This would include maintaining separate fixed asset sub-ledgers and accounting for any disposals, de-recognition and depreciation of such assets in such ledgers differently from the underlying books and records maintained for IFRS general purpose financial statements. Additionally, reconciliations to reported information may be required.

If the Board chooses the alternative that requires retrospective restatement of historical PP&E, the impact on the utilities will depend upon which transition method they choose for their general purpose financial statements. In the event a utility chooses a transition method that is inconsistent with this alternative, then transition costs will increase. Any adjustment arising on transition would also need to be addressed. There may be no need to maintain two separate sets of financial records for existing PP&E if the utilities chose the same IFRS compliant accounting policies for their general purpose financial statements as is required for their regulatory reporting.

If the Board were to choose the fair value alternative, then utilities would need to determine an appropriate method for measuring fair value. This often results in significant and subjective judgments being made in estimating fair value, resulting in significant measurement uncertainty. Establishing fair value may require qualified professional valuators to perform comprehensive revaluations of the historical assets. Any adjustment arising on transition would also need to be addressed. Similar to the retrospective restatement, there would be no need to maintain two sets of financial records if the utilities elected to use fair value for their general purpose financial statements.

In summary:

Alternative	Implications for utilities
Historical Cost	▪ No conversion activities necessary ▪ Separate IFRS records will be prepared for general purpose financial statements with reconciliations likely required
Retrospective Restatement	▪ Significant time and effort required to identify and segregate the non-compliant historical costs ▪ Reconciliation of historical regulatory rate base and IFRS not required ▪ Transition difference to be addressed
Fair value	▪ Significant time and effort required to determine fair value ▪ Reconciliation of historical regulatory rate base and IFRS not required ▪ Transition difference to be addressed

iii. Implications for the rate-making process

If the Board chooses the NBV alternative, then the basis of rate base will not change as a result of the conversion to IFRS. However, since the general purpose financial statements of the utilities will be based on IFRS, there will likely be a need for the Board to require reconciliation between the rate base and the underlying PP&E records.

If the Board requires retrospective restatement of historical PP&E, then the rate base post transition to IFRS changes. Any adjustment arising on transition would also need to be addressed. Additional reconciliation requirements would not be required (assuming the utility made the same transition choice for its general purpose financial statements).

If the Board were to choose the fair value alternative, then the Board may need to provide additional guidance on what would constitute an appropriate method for determining fair value in order to avoid inconsistent application among utilities. Similar to the retrospective restatement, there could be a material change in the overall rate base unrelated to underlying operations, which would need to be addressed. There would be no need to perform reconciliations between IFRS PP&E and rate base (assuming the utility made the same transition choice for its general purpose financial statements).

In summary:

Alternative	Implications for the rate making process
Historical Cost	▪ Consistent with current practice ▪ Reconciliation required for on-going rate submission ▪ Possible additional assurance requirements
Retrospective Restatement	▪ Transition adjustments to be addressed ▪ No reconciliation of historical PP&E required between regulatory rate base and IFRS (assuming accounting policy choice consistent)
Fair value	▪ No reconciliation of historical PP&E required between regulatory rate base and IFRS (assuming accounting policy choice consistent) ▪ Transition adjustments to be addressed

3.2 Rate base after transition to IFRS

This section addresses the following question:

"After adoption, what should be the basis for reporting PP&E for regulatory purposes (e.g. historical acquisition cost, fair value)?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Currently, the Board requires that utilities report PP&E based on acquisition cost. This cost contains various elements as discussed in further detail in questions 3.3 and 3.4.

There is no provision under CGAAP for the revaluation of PP&E, unless there is a comprehensive revaluation of assets and liabilities due to a financial reorganization, a change in the control of virtually all of the equity instruments (i.e. CICA Handbook 1625) or through a business combination accounted for using the purchase method.

ii. Requirement under IFRS

Under IFRS, an entity has the option of choosing either the cost model or the revaluation model as its accounting policy, and applying that policy to an entire class of PP&E.

Under the cost model, an item of PP&E is carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Under the revaluation model, an item of PP&E whose fair value can be measured reliably is carried at the revalued amount, being the fair value at the date of revaluation less any subsequent accumulated depreciation, and subsequent accumulated impairment losses. Revaluations are to be made with sufficient regularity to ensure that the carrying amount does not differ materially from the current fair value.

iii. Summary of the accounting difference that will exist

Outside of a business combination or re-organization, for the first time Canadian utilities will have the option to carry their assets (PP&E and Intangibles) at fair value rather than at cost for general purpose financial reporting.

It is uncertain at this time as to the extent that this option will be adopted by utilities.

B. Range of alternatives available

i. Alternative 1 – Cost

The Board could choose to require assets to be reported on a cost basis.

ii. Alternative 2 –Fair value

The Board could require all utilities to record assets at fair value.

iii. Alternative 3 – Cost or Fair value

The Board could allow utilities the choice that exists within IFRS, i.e. to choose to measure their assets at either cost or fair value.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

If the Board were to require assets to be reported based on cost, apart from the impacts arising as a consequence of the differences in IFRS basis of cost (refer section 3.3), there would be consistency with current rate processes and no impacts on rate payers.

If the Board chooses the fair value alternative, then the Board will need to assist in determining an appropriate method for measuring fair value, and provide direction to the utilities in applying that method to their rate base submission. Rate base, and ultimately rates, will then potentially depend on significant subjective judgments that are applied in estimating fair value. Since there would be no direct linkage between the rate base submission and incurred costs, this fair value alternative would lead to a potential disconnect between the cost of the network, and the value being assigned to rate base, which is a significant divergence from the current cost of service model. Additionally, the variable nature of fair value accounting could lead to larger fluctuations in the rate base figures submitted, potentially leading to more volatility for ratepayers.

If the Board allowed a utility the choice to measure its assets at either cost or fair value, and allowed those values to flow through to rate base, then this may lead to inconsistency in the basis of rate setting and therefore rates across different utilities.

In summary:

Alternative	Implications for the rate payers
Cost model	▪ Status quo
Fair value model	▪ Inconsistent with the cost of service rate-making ▪ Increased volatility in rate base and rates
Cost or fair value	▪ Inconsistent basis for rate setting

ii. Implications for utilities

If the Board were to require a cost model, apart from any impacts arising as a consequence of the differences in IFRS basis of cost (refer section 3.3), then there would be no impact on utilities.

If the Board chooses the fair value alternative, then utilities will need to determine an appropriate method for measuring fair value (perhaps as mandated by the Board), and may require professionally qualified valuators to assist with the ongoing measurement of fair value. Utilities may need to perform these valuations regularly to ensure that carrying amounts are not materially different from fair value which would lead to potential ongoing changes in rate base value, and significant investments of time and resources. In addition, if assets are revalued, then there will be additional systems and process implications to ensure appropriate tracking of revaluation adjustments and possible reversals, should fair values decline. In addition, the variable nature of fair value accounting and therefore rate base, would lead to more volatility in reported earnings.

Furthermore, if the utility makes an accounting policy choice which is inconsistent with Board requirements, then two sets of accounting records will need to be maintained as previously discussed.

If the Board allows the utility to choose between measuring its assets at cost or fair value, this allows for consistency between the choice a utility makes for IFRS general financial reporting purposes and regulatory purposes.

In summary:

Alternative	Implications for utilities
Cost model	▪ Status quo ▪ Possible multiple set of books
Fair value	▪ Effort to maintain and update fair value records ▪ Increased volatility in rate base and reported earnings ▪ Possible multiple set of books
Cost or fair value	▪ Minimize likelihood of multiple sets of books

iii. Implications for the rate-making process

If the Board were to require a cost model then there is unlikely to be any impact on the current rate-making processes, apart from any changes which may arise from 3.3 or 3.4.

If the Board were to require the fair value alternative, then the Board would need to provide additional guidance on what would constitute an appropriate method for determining fair value. There could be material changes in the overall rate base submissions, which would need to be addressed, since these changes would not relate to the underlying operations of the entities. The Board may also need to spend time analyzing the appropriateness of the fair value calculations because there will likely be significant judgement on the part of the utilities when determining these values.

If the Board were to allow utilities the choice between cost and fair value then the Board should prepare for inconsistency in reported information.

In summary:

Alternative	Implications for the rate making process
Cost method	▪ Rate submission process would remain the same
Fair value	▪ Rate submission process would need to change to meet new standards ▪ The rate setting process would need to include a review of the methods used to determine fair value ▪ Potential volatility in rate base and rates
Cost or fair value	▪ Inconsistency in underlying basis of reported information

3.3 Capitalization Policies

This section addresses the following question:

"Should the Board require PP&E to conform to IFRS capitalization requirements (e.g. capitalize less indirect overhead and administration cost than permitted under current Canadian GAAP)?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Currently, utilities report PP&E based on acquisition cost including a burden component. This burden component may include an element of general engineering and administrative salaries and expenses, and insurance, for example. In practice capitalization policies across the industry vary. In some instances, utilities have developed complex overhead cost allocation models to support the capitalization of many support-type functions, including executive costs, HR, IT and materials and procurement functions. The utilities with larger capital expenditure programs would tend to fall into this category. In other instances, capitalized costs are limited to direct labour and materials costs.

ii. Requirement under IFRS

IFRS requires that assets be recorded at their cost. Cost is defined to include acquisition costs, plus other costs that may be directly attributable to the asset. IFRS explicitly defines cost to include dismantling and decommissioning costs but excludes administration, and general overhead, including training costs.

Administration and general overhead is not defined in IFRS and authoritative interpretation does not exist. Individual entities will be required to develop their own policies in order to implement these new requirements. Given this lack of definitive guidance we expect that there will be continued variability in capitalization policies in this industry.

iii. Summary of the accounting difference that will exist

We anticipate that the capitalization policies developed to comply with IFRS will differ relative to the capitalization policies currently applied. For some utilities this will lead to less costs being capitalized relative to current policies, however, the reverse may also be the case.

B. Range of alternatives available

i. Alternative 1 – Existing CGAAP accounting method

The Board could choose to allow utilities to continue current capitalization practices for rate base purposes.

ii. Alternative 2 – IFRS compliant method

The Board could choose to require all utilities to apply the IFRS definition of cost for rate base purposes with or without direction.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

If the Board were to choose the status quo, then the existing approach that has been followed by utilities for setting rate base would continue to apply in the future. The amounts included in rate base in future submissions would be entirely consistent with past rate submissions. As a result, the transition to IFRS would have no impact on the rate base component of the rate calculation.

If the Board were to require that the cost of PPE be determined in accordance with IFRS, then there is a likelihood that over time the total rate base would be less relative to the currently approved method. If no other business changes are made, then reductions in rate base would in turn lead to an equivalent increase in the OM&A component of the rate submissions. Net rates would rise in the short term as costs that were traditionally born by ratepayers over the life of the assets due to capitalization would now be born entirely in the year they are incurred. This initial rise in rates would be offset by subsequent reductions in rates as a result of lower depreciation charges in later years.

In summary:

Alternative	Implications for the rate payers
Existing capitalization policy	▪ Status quo ▪ Rates would remain consistent with prior submissions
IFRS capitalization policy	▪ Burden costs would likely change in future submissions ▪ Costs would likely be recovered from ratepayers more quickly

ii. Implications for utilities

If the Board chooses to allow current capitalization policies to continue, then utilities would use existing costs as the basis for their rate submissions. They may be required, however, to maintain a separate set of financial records for the purposes of producing their general purpose financial statements if their current capitalization policies are not acceptable under IFRS. This may mean that PPE transactional level data would need to be maintained on two different bases. Additionally, reconciliation to reported information may be required.

If the Board were to require rate base to be determined in accordance with IFRS capitalization policies, then utilities would not need to maintain two separate sets of records for PP&E acquired/constructed subsequent to transition to IFRS.

In summary:

Alternative	Implications for utilities
Existing capitalization policy	▪ Multiple sets of books may be required
IFRS capitalization policy	▪ Minimize need for multiple sets of books

iii. Implications for the rate-making process

If the Board chooses to require the continuation of current capitalization policies for PPE, then the basis of the rate base remains the same. However, since the audited general purpose financial statements for the utilities will be based on IFRS, there may be a need for the Board to review reconciliations between the rate base and PP&E records maintained to support general purpose financial reporting.

If the Board were to require capitalization policies to conform to IFRS, then rate base after the transition to IFRS may be lower than rate base currently submitted, with an equivalent increase in OM&A. This increase may be passed on to ratepayers in the form of increased rates, but does not relate to any material change in the underlying operations or cash flows of the utilities. It would, however, be followed by offsetting reductions in rates over the life of the underlying assets as depreciation charges in future years reduce. These impacts would need to be managed by the Board. The process of review of rate submissions should be no more extensive than current processes since the rate submission would be consistent with underlying audited general purpose financial statements.

In summary:

Alternative	Implications for the rate making process
Existing capitalization policy	▪ Rate submission process would remain the same ▪ Reconciliation between rate base and audited general purpose financial statements
IFRS capitalization policy	▪ Changes to internal rate submission process ▪ No reconciliation between rate base and audited general purpose financial statements ▪ Potential rate increase, offset in future years

3.4 Rate base values for other PP&E related items

This section addresses the following question:

"What changes to existing regulatory or rate making treatments should the Board require for other PP&E related items as a result of the adoption of IFRS?

- Borrowing costs applied to PP&E (as opposed to deemed interest or AFUDC);
- Customer contributions received for PP&E;
- Asset reclassifications from PP&E to intangible assets (e.g., computer software and land rights);
- Asset retirement obligations;
- Gains and losses on disposition of assets; and
- Treatment of asset impairment."

This section includes discussion of a number of differences between IFRS and current requirements that are particularly relevant to the determination of the carrying value of PP&E and therefore to the value of rate base.

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Borrowing Costs

Under CGAAP, carrying costs such as interest that are directly attributable to the construction of an asset may be capitalized. Utilities are allowed to capitalize an allowance for funds used during construction ("AFUDC") as determined by the regulator, into the value of rate base. AFUDC may or may not reflect borrowing costs actually incurred.

In Ontario, the OEB prescribes the AFUDC rate based on a variable market-determined interest rate i.e. the yield rate for the DEX Mid-Term Corporate Bond Index.

In practice, not all regulated utilities currently capitalize AFUDC. It seems that there is a tendency for larger utilities, which tend to have a greater incidence of qualifying construction activity, to capitalize this cost.

Customer Contributions Received for PP&E (i.e. transfers of assets from customers)
When a customer or property developer contributes funds to a utility for the purpose of building new assets or contributes actual items of PP&E, the utility is required to capitalize the cost in PPE, with an offsetting amount recorded as a negative asset, or a liability. The effect of this is that no amount is recorded in rate-base for the amount of customer contributions received. This accounting treatment applies for both rate-setting and general purpose financial statements.

Asset Reclassifications
Currently land rights and software are generally classified as either items of PPE or intangible assets in general purpose financial statements. When such assets are classified in PPE they are considered as part of the value of rate base for regulatory purposes.

CGAAP was recently changed with effect for fiscal year ends beginning on or after October 1, 2008 and will require intangible assets, such as land rights and software to be classified as intangible assets unless they considered to be operating leases (land rights) or an integral part of underlying tangible assets (land rights or software). At this stage it is uncertain if utilities will make any reclassifications in their CGAAP financial statements and what, if any, the Board's views on such reclassifications would be. As such, the impacts on rate base are as yet unclear.

Asset Retirement Obligations (AROs)
Under CGAAP, an ARO is recorded if a utility has a legal obligation (either by existing or enacted law, statute, written or oral contract, etc) to incur expenditure associated with the retirement of an asset.

Further, a utility is required to record a provision for an ARO only if the fair value of the obligation can be reasonably estimated. In practice, transmission and distribution utilities do not generally record AROs in respect of their system assets unless there are specific plans to remove individual parts of the system, e.g. a specific distribution substation. It is often argued that an entity cannot reliably determine when a specific asset will be removed, and that, therefore, a reasonable estimate of the fair value cannot be determined. In such circumstances no liability is recognized and the unrecorded liability is disclosed as a contingent liability.

However, in some circumstances, where allowed by the regulator, costs associated with the dismantling, removal and disposal of items of PP&E (e.g. negative salvage values) are estimated and built into the annual depreciation charges and hence collected in rates over the estimated life of the asset. When costs are subsequently incurred to dismantle and remove the asset, these are charged against the accumulated depreciation.

Gains and Losses on Disposition of Assets
Under CGAAP, special exemption is made for rate-regulated operations when the regulator requires that any gain or loss arising on the disposal of assets be considered in the determination of future rates charged to customers. In such circumstances, the gain or loss is deferred and is not immediately recognized in the income statement.

Impairment
Under CGAAP, an asset (or asset group) is first assessed for impairment based on whether the asset's (or asset group's) carrying amount exceeds the expected undiscounted future cash flows of the asset (or asset group). If impairment exists, then the impairment loss is measured based on the excess of carrying amount over the fair value of the asset (or asset group).

Also, CGAAP does not permit any previously recognized impairment losses to be reversed.

ii. Requirements under IFRS

Borrowing Costs
Under IFRS, all borrowing costs that are incurred on a qualifying asset are required to be capitalized. This is not an accounting policy choice. A qualifying asset is defined as "an asset that necessarily takes a substantial period of time to get ready for its intended use or sale." This definition is open to interpretation and there is some inconsistency as to how it is interpreted under IFRS in practice. It is not uncommon for entities in this industry to capitalize borrowing costs only on capital projects that are of 12 months or longer duration. However, in our view anything well in excess of 6 months will also be acceptable.

IFRS requires capitalization of the borrowing cost that is actually incurred by an entity. It is not a deemed amount. Borrowing costs can either be specific to a particular project or result from the entity's general borrowings. Where general borrowings are used, a capitalization rate that is based on the entity's actual weighted average borrowing rate is applied to the actual project expenditures incurred.

Customer Contributions Received for PP&E (i.e. transfers of assets from customers)
When a customer or developer transfers funds for the purpose of building new assets or transfers an asset to a utility, IFRS requires the following treatment:

- If an item of PP&E is received and the utility concludes that it controls the asset, then the item of PP&E is measured initially at fair value (refer Section 3.1 for discussion on the fair value of PP&E); and

- If cash is received, the item of PP&E that the utility constructs is measured initially at cost.

Under IFRS the offsetting "credit" for the customer contribution is recognized as revenue in accordance with the timing and nature of the performance obligations underlying the arrangement. In exchange for the transferred item of PPE, a utility may agree to deliver one or more services, such as connecting the customer to a network, providing the customer with on-going access to a supply of goods or services, or both. IFRS requires the services included in the agreement to be determined and revenue to be recognized in accordance with these services. This may mean that revenue is recognised in full on connection to the network or over a period of time, such as the contractual period, or in the absence of a specified contract term, the life of the underlying PP&E.

Asset Reclassifications
Under IFRS, land rights that represent an access right would be accounted for as intangible assets. Those land rights that represent the right of use of a third party's assets (e.g. land) would be accounted for as leases, and any amounts paid for the right of use of land would be treated as prepaid operating lease expenses.

Further, software that is not an integral part of the related hardware would be classified as intangible assets.

Asset Retirement Obligations (i.e. decommissioning and restoration obligations)
Under IFRS, liabilities relating to decommissioning and restoration activities are recognized for both legal and constructive obligations.

Under IFRS, the amount recognized as a provision is the best estimate of the expenditure required to settle the present obligation. It is rare for a liability not to be recognized because the amount cannot be estimated reliably. In particular, IFRS has greater guidance on how uncertainties surrounding the amount to be recognized as a provision are taken into account in determining the best estimate of the liability. Statistical methods can also be used for estimating the expected value of the liability.

Gains and Losses on Disposition of Assets
IFRS requires that gains and losses be recognized at the time that an item of PP&E is disposed. The gains and losses must be recognized in the income statement, and cannot be offset against any remaining PP&E balances, or deferred on the balance sheet.

Impairment
An impairment loss is recognized if the carrying amount of an asset/cash generating unit (CGU) exceeds its recoverable amount. The recoverable amount is the greater of (i) its fair value less costs to sell (external measure of value) and (ii) its value in use, which is based on the net present value of future cash flows (internal measure of value). The impairment loss equals the amount of this excess.

Under IFRS, an entity is required to assess at each reporting period whether there is an indication that an impairment loss recognized on PP&E in prior periods has reversed. The impairment loss is reversed if the recoverable amount of the item exceeds its carrying amount.

iii. Summary of the accounting differences that will exist

The differences arising in connection with these specific areas that lead to a change in the value of PPE reported in general purpose financial statements and the values underlying rate base are as follows:

Borrowing Costs
Utilities will have to capitalize borrowing costs incurred on qualifying assets. The capitalization of a deemed amount of borrowing costs (AFUDC) is not permitted under IFRS. Utilities will have to capitalize borrowing costs, reflecting the actual cost of debt to the utility.

These differences are unlikely to be material for those smaller utilities that do not undertake significant capital projects.

Customer Contributions Received for PP&E (i.e. transfers of assets from customers)
Under IFRS the accounting treatment for capital contributions could be substantially different from that generally applied today. The value of contributed assets will be included in the carrying value of PP&E. Revenue will be recorded in accordance with the performance obligations underlying the arrangement.

Asset Reclassifications
Land rights and software licenses would be reclassified from PP&E to intangible assets or prepaid operating lease expenses. Since intangible assets/prepaid operating lease expenses and the amortization of intangible assets are currently not specifically included in the rate base definitions this would have to be addressed to determine whether it would have an impact in determining rates.

Asset Retirement Obligations (i.e. decommissioning and restoration obligations)
As IFRS will also require provisions to be recognized for constructive obligations, a regulated utility may record more dismantling and decommissioning obligations than they would under current CGAAP. This would result in an increase in carrying value of PP&E as well as the depreciation charge. In addition, since IFRS requires that an estimate is made, items that were previously only disclosed in the notes as contingent liabilities may give rise to actual provisions under IFRS.

Gains and Losses on Disposition of Assets
IFRS could lead to greater volatility in the income statement because gains and losses must be recognized for all material PP&E disposals. The net impact would depend on the volume and magnitude of the gains and losses recognized during each period.

Impairment
After transition to IFRS, if there is an indication that an impairment loss may no longer exist or may have decreased, utilities are required to re-assess and reverse any previously recognized impairment losses.

B. Range of alternatives available

i. Alternative 1 – Continue using existing rate making treatment

The Board could choose to continue mandating the current treatment for the above PP&E related items, irrespective of how they are accounted for in the general purpose financial statements.

ii. Alternative 2 – Use IFRS treatment for rate making purposes

The Board could choose to require all utilities to conform to the IFRS standards for the above PP&E related items.

iii. Alternative 3 – A Hybrid approach

The Board could consider the above PP&E related items individually, and could require utilities to transition to IFRS standards for some, while maintaining the current treatment for others.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

If the Board were to choose the status quo alternative, then the existing rate base approach that has been followed by utilities in past rate submissions would continue to apply. The amounts included in rate base in future submissions would be entirely consistent with past rate submissions. As a result, the transition to IFRS would have no impact on the rate base component of the rate calculation. However, rate payers may need to review and understand reconciliations between the utilities' general purpose financial statements and their regulatory submissions because there is likely to be fundamental differences between the treatments of these PP&E items.

If the Board were to choose to transition to the IFRS treatment for these PP&E items, then the effects would be as follows:

- Some changes in the amount of borrowing costs capitalized, leading to changes in the rate base for constructed assets.
- An increase in the rate base of PPE due to the change in the accounting treatment of customer contributions. Without any changes to rate making policy to reduce rate base by the net amounts contributed, rate payers would be funding the cost of assets that had not been incurred by the utilities.
- Land rights and software licenses would transfer out of the rate base of PPE as currently defined, leading to lower overall rate base.
- Higher provisions for asset retirement obligations may create an increase in rate base.

- Increased gains and losses on disposed assets may lead to greater volatility in operating results (and rates) depending on the nature, timing and materiality of disposals.

If the Board were to choose to adopt the IFRS standards for only a portion of the specific PP&E items described above, then the overall impact on rates becomes less clear. It would depend entirely on which items the Board chose to transition. It may, create some complexity amongst rate payers in interpreting the rate submissions of the utilities when compared with their audited financial statements because the rate submission would not be entirely consistent with either past submissions or the new IFRS standards.

In summary:

Alternative	Implications for rate payers
Existing treatment	▪ Status quo ▪ Rates would remain consistent with prior submissions ▪ May need reconciliations between general purpose financial statements and rate submissions
IFRS treatment	▪ More rate volatility ▪ No additional reconciliations
Hybrid treatment	▪ Not possible to determine the impact on rates ▪ Would introduce complexity

ii. Implications for utilities

If the Board were to choose to retain the existing treatment of these PP&E items, then utilities would use existing practices as a basis for their rate submissions, but would be required to prepare and maintain a separate set of financial records, perhaps at the transactional level for IFRS financial reporting purposes. This would lead to increased time and effort for reporting, and likely additional system and process changes to manage any dual-reporting requirements, including reconciliations.

If the Board were to choose to follow all the IFRS requirements, then utilities would not need to maintain two separate sets of financial records for PP&E. However, in the absence of changes then being made to the rate making process and metrics:

- A change in the amount of borrowing costs capitalized would lead to changes in the rate base and revenue requirement;
- An increase in the rate base due to the change in the accounting treatment of customer contributions may lead to gains for the utilities as rate payers would be funding the cost of assets that had not been incurred by the utilities;
- Land rights and software licenses would transfer out of the rate base of PPE, leading to a lower overall rate base and revenue requirement; and
- Higher provisions for asset retirement obligations may create an increase in rate base and revenue requirement.

If the Board were to choose the hybrid approach, then the utilities could not use existing practices as a basis for their rate submissions, but would still be required to prepare and maintain a separate set of financial records for IFRS general purpose financial reporting. This could lead to complexity on the part of the utilities because their rate submission would reflect neither a historically consistent, nor an IFRS consistent approach. The utilities may also need to prepare and maintain additional reconciliations.

In summary:

Alternative	Implications for utilities
Existing treatment	▪ Status quo ▪ Rates submission process would remain consistent with prior process ▪ Multiple sets of books
IFRS treatment	▪ Rate submission process would need to be adjusted ▪ No need to maintain multiple sets of books ▪ Possible significant changes in the value of rate base
Hybrid treatment	▪ Rate submission process would need to be adjusted ▪ Multiple sets of books ▪ Would introduce complexity

iii. Implications for the rate-making process

If the Board were to choose the status quo alternative, then the existing rate base approach that has been followed by utilities in past rate submissions would continue to apply. The amounts included in rate base in future submissions would be entirely consistent with past rate submissions. As a result, the transition to IFRS would have no impact on the rate base component of the rate calculation. The methods and metrics used for evaluating submissions would not need to change, but there would likely be a need to review and understand reconciliations between general purpose financial statements and regulatory submissions.

If the Board were to choose the IFRS compliant alternative, then the methods and metrics used to evaluate rate submissions would need to be adjusted to reflect the new IFRS requirements, however, there would be no additional reconciliation requirements.

In addition, a change to using actual incurred borrowing costs may eliminate the need for the Board to prescribe a rate for carrying charges for capital work in progress.

If the Board were to choose the hybrid approach, then the methods and metrics used to evaluate submissions would need to be changed to address the impacts of adopting the IFRS requirements for certain items of PP&E. This could lead to increased complexity during the rate submission process because the submissions would reflect neither a historically consistent, nor an IFRS consistent approach. There would be a need to review and understand reconciliations between the records maintained for general purpose financial reporting and the regulated rate base calculation.

In summary:

Alternative	Implications for the rate making process
Existing treatment	▪ Rates submission process consistent ▪ Method and metrics for reviewing submissions unchanged ▪ Additional reconciliations
IFRS treatment	▪ Rate submission process would need to be adjusted ▪ No additional reconciliation ▪ May eliminate need to prescribe a rate for carrying charges ▪ Methods and metrics for reviewing submissions would need to be adjusted
Hybrid treatment	▪ Rate submission process would need to be adjusted ▪ Additional reconciliations ▪ Methods and metrics for reviewing submissions would need to be adjusted

4. Depreciation

4.1 Parameters for depreciation accounting

4.2 Parameters for depreciation rates

This section addresses the following questions:

"Should the Board set parameters for depreciation accounting for regulatory purposes (e.g. depreciation methods, the level at which sub-componentization should be applied to specified asset classes)?"

and

"Should the Board set the parameters for electricity distributors to establish their own depreciation rates rather than continue to use depreciation rates historically provided by the Board (co-ordination of depreciation studies may be possible)?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Depreciation methods

Depreciation is a charge to income that recognizes that the life of an item of PP&E (other than certain land) is finite. The finite life is normally the shortest of the item's physical, technological, commercial or legal life. Depreciation must be recognized in a rational and systematic manner appropriate to the nature of the item of PP&E.

The depreciation method and estimates of the life and useful life of an item of PP&E are reviewed on a regular basis. Factors to be considered in this regard include expected future usage, expected wear and tear from use or the passage of time, results of studies made regarding the industry, studies of similar items retired, and the condition of existing comparable items. In addition, entity-specific circumstances such as maintenance programs and service standards can alter an item's expected useful life.

There is no currently prescribed method that must be used to depreciate capital assets for general purpose financial statements. Instead, judgment must be used in choosing the depreciation method appropriate to the nature of the capital asset based on its use by the enterprise and its estimated useful life. For rate setting purposes, a number of utilities apply the depreciation rates and methods that were previously included in the "Accounting for Municipal Electric Utilities in Ontario" manual ("MEU Manual"). Such utilities have not conducted independent depreciation studies.

Unit of measure and components

For both financial reporting and rate setting purposes, if an item of PP&E is made up of significant separable component parts, its cost must be allocated to component parts when practicable and when estimates can be made of the lives of the separate components. Depreciation is then calculated for each component separately. Separable component parts are further defined in the APH as "readily identifiable assets", i.e. assets of a material unit cost which are tracked separately. In accordance with the APH, if such assets are retired or disposed of, then a gain/loss should be recognized in income in the period the transaction occurs.

It is recognized, however, that in this industry there are a large number of capital assets that are individually insignificant. It is common practice, therefore, to group such assets for the purposes of both general purpose financial reporting and rate setting. These asset groupings are amortized such that the combined cost of the assets is amortized over their estimated useful life. This is often referred to as the group depreciation method. The estimate of useful lives may be supported by extensive statistical depreciation studies.

Application of the group depreciation method results in:

- gains and losses on the de-recognition of individual assets not being recognized directly in income. Assets remaining in use after reaching the end of their average useful life are not regarded as fully depreciated until actual retirement. On retirement of such assets, the accumulated amortization account is charged with the book cost of the property retired and the cost of removal and disposal and is credited with the salvage value and any other amounts recovered; and

- obligations for dismantling and removing items of grouped PP&E are not recognized as liabilities. Instead, the asset is over-depreciated during its life such that at the end of its useful life, a negative value is recorded (i.e. negative salvage values) within PP&E. The costs that are subsequently incurred to dismantle and remove the asset are then charged against accumulated depreciation.

ii. Requirement under IFRS

Depreciation methods

The IFRS requirements for depreciation are largely the same as current requirements, except that it is possible that the group depreciation method as currently practiced by some utilities may not be acceptable under IFRS.

Also, under IFRS, the review of useful lives, depreciation methods and residual values is required to be conducted at each financial year end, at a minimum.

Unit of measure and components

IFRS does not prescribe the unit of measure for recognition, i.e. what constitutes an item of PP&E. Thus, judgment is required in applying the recognition criteria to an entity's specific circumstances. IFRS contemplates the pooling of individually insignificant items.

As accounting for components is more rigorously followed under IFRS, utilities may be required to follow the components approach more closely with respect to the depreciation and de-recognition of significant parts of items of PP&E. IFRS also recognizes both physical and non-physical components. Therefore, costs of major overhaul or inspection embodied in a capital asset may need to be split out and depreciated over a shorter period of life than the actual physical asset.

IFRS also requires that upon retirement or disposal of assets (including grouped/pooled assets), any resulting gain or loss is to be recorded in the income statement (see Section 3.4). In addition, any legal or constructive obligations for dismantling and removing an item of PP&E are recorded as part of the initial cost of the item of PP&E and are depreciated over that item's useful life (see Section 3.4).

iii. Summary of the accounting differences that will exist

Under a cost of service regulatory model depreciation is the primary element for recovery of capital costs in rates by utilities. Any change in the manner in which depreciation is calculated has the potential to impact rates. The key accounting differences that will arise upon transition to IFRS are:

- The depreciation methods, useful lives and residual values for items of PP&E will need to be reviewed to ensure compliance with IFRS. The use of depreciation methods and rates previously established under the MEU Manual may no longer be appropriate;
- The significant components of items of PP&E, both physical and non-physical, will have to be identified. The components approach is likely to be more rigorously applied under IFRS for the purposes of depreciation and de-recognition of items of PP&E; and
- For grouped assets, gains and losses will have to be recognized in the income statement upon the retirement or disposal of items of PP&E and provisions recognized for dismantling and removal costs, where appropriate (see Section 3.4). This may or may not have a material impact on actual reported earnings, since such amounts are currently included in an annual depreciation charge.

B. Range of alternatives available

i. Alternative 1 – set parameters with no options to their application

The Board could prescribe depreciation methods, useful lives and residual values for items of PP&E. In addition, it could provide specific direction on the types of components that should be recognized. Each utility would then follow these pre-determined OEB parameters and would not adjust them for entity-specific circumstances in their rate applications. The OEB could continue to use the parameters provided in the MEU Manual, or it could set new parameters. The Board may be able to establish these new parameters after having co-ordinated industry-wide depreciation studies.

ii. Alternative 2 – set parameters with options

As with Alternative 1, Alternative 2 provides for the OEB to set depreciation parameters and approaches to identifying components. Unlike Alternative 1, however, the OEB would allow utilities to change these parameters to reflect their unique or specific circumstances. Justification may be required for such changes. This alternative is broadly in line with the current practice. The OEB could continue to use the parameters provided in the MEU Manual, or it could set new parameters.

The Board may be able to establish these new parameters after having co-ordinated industry-wide depreciation studies.

iii. Alternative 3 – do not set parameters

The Board could choose not to prescribe any parameters whatsoever, but require that each utility establishes its own depreciation methods and rates.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

Depreciation charges are a significant component of the costs included in rates. Ratepayers will be interested in determining that the depreciation charges are fair and reasonable.

Although prescribed depreciation parameters would result in greater consistency, there is a risk that the permitted rates may not be fully representative of the actual depreciation at each utility. This would result in a mismatch between the amount that is being recovered in rates and the actual depreciation cost of utilities.

Establishing depreciation parameters while also giving the utilities an option to justify changes based on their entity-specific circumstances would retain some consistency. However, when justified, the depreciation that is included in rates would be determined in individual rate applications.

Alternative 3, in which the Board sets no parameters for depreciation, would possibly result in inconsistency of the amount that is included in rates. However, provided that the amounts claimed are reasonable and in line with actual amounts justified by the utilities in their general purpose financial statements, it is unlikely that the mismatch that is described above would arise.

In summary:

Alternative	Implications for rate payers
Set parameters with no option	▪ Consistency ▪ Potential mismatch in recovery of depreciation charge
Set parameters with an option	▪ Some consistency ▪ Some potential mismatch in recovery of depreciation charge
Set no parameters	▪ No guarantee of consistency ▪ Reduced likelihood of mismatch in recovery of depreciation charge

ii. Implications for utilities

The specific circumstances of individual utilities will differ across the province. Various technical and other entity specific factors may influence the depreciation methods and useful lives of items of PP&E (e.g. expected maintenance programs and service standards, mix of customer base, usage and climatic differences).

Although using prescribed methods and rates would simplify the rate application process by reducing the burden of having to justify alternative methods, entity specific circumstances will have to be taken into account in the depreciation charge that is recorded in the general purpose financial statements to ensure the provisions of IFRS are met. As a result, the utilities will still need to conduct entity specific reviews for their general purpose financial statements. Any differences would possibly result in the need for two sets of books to be maintained or require an extensive reconciliation process to the audited general purpose financial statements.

In addition, prescribed depreciation methods and depreciation rates may lead to a situation whereby permitted rates are not fully representative of actual depreciation at a utility.

In summary:

Alternative	Implications for utilities
Set parameters with no option	▪ Simplified rate application process ▪ Potential mismatch in recovery of depreciation charge ▪ Two sets of books and additional reconciliation process
Set parameters with an option	▪ Some utilities may benefit from a simplified rate application process ▪ Some potential for mismatch in recovery of depreciation charge ▪ May need two sets of books and reconciliation process
Set no parameters	▪ Rate application process more complex and detailed ▪ Reduced likelihood of mismatch in recovery of depreciation charge ▪ No need for two sets of books or reconciliation process

iii. Implications for the rate-making process

Prescribing depreciation methods and rates while at the same time seeking to establish just and reasonable rates given each utility's specific circumstances may prove to be a challenging exercise. The Board would possibly need to conduct regular depreciation studies in order to maintain appropriate methods and rates to be applied. However, due to the large number of utilities of differing sizes and types of assets within the province of Ontario, it may be a complicated and costly exercise. Other practical issues for the Board to consider include how a representative sample of PP&E used by the various utilities would be determined, how such a depreciation study would be funded and the extent to which individual utilities would be expected to rely on the results of such a study.

Alternatively, the Board could opt to use the depreciation methods and rates set out in the MEU Manual or it could select new rates after rate hearings. However, in all instances it is possible that utilities could challenge some of the findings as their entity specific considerations may not always have been fully reflected in the prescribed methods and rates that are established.

Alternative 3 would require each utility to make its own judgment with regards to the depreciation methods and rates to be applied. It is possible that utilities can make different judgments on the same set of facts and circumstances in applying this requirement.

In summary:

Alternative	Implications for the rate making process
Set parameters with no option	▪ Regular depreciation studies increase regulatory administrative burden ▪ May simplify the rate application process ▪ Risk of increased disputes
Set parameters with an option	▪ Some administrative burden on the regulator ▪ Disputes avoided ▪ Status quo is maintained
Set no parameters	▪ No administrative burden on the regulator ▪ May complicate rate application process ▪ Possible inconsistency in judgments

5. Other Issues

5.1(a) Inventory Valuation

This section addresses the following question:

"What changes to existing regulatory accounting and rate treatments should the Board require for inventory valuation (based on lower of cost and net realizable value)?"

In considering this question, we have focused our comments primarily on natural gas inventory.

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

For financial reporting purposes, CGAAP requires inventories to be recorded at their actual cost and, at reporting period end, valued at the lower of cost and net realizable value.

Due to the effect of rate regulation, however, for financial reporting purposes natural gas distribution utilities record natural gas inventory at forecast quarterly prices approved by the OEB. The forecast purchase price, known as the weighted average cost of gas (or "WACOG"), is meant to represent actual natural gas costs and is estimated based on the market information available at the time. The actual purchase price of the natural gas may differ from this forecast price.

The difference between the actual purchase price of the natural gas and WACOG is deferred as a regulatory asset or liability for future collection or refund to the customers when approved by the OEB. Effectively, general purpose financial statements record inventory and cost of gas sold at WACOG and accordingly, no profit or loss on the gas commodity is currently recognized in the income statement.

ii. Requirement under IFRS

IFRS requires inventory to be recorded at acquisition cost and then at the period end to be valued at the lower of cost and net realizable value.

In applying the IFRS requirements, when the net realizable value of inventory is lower than cost, a write-down in value is recognized in the income statement in the period in which the write-down occurs. Write-downs may be reversed if the net realizable value subsequently increases.

Cost may be determined by using a weighted average cost formula. However, this must approximate acquisition cost.

iii. Summary of the accounting difference that will exist

Under IFRS, cost of inventory sold during a period reflects the acquisition cost of inventory sold (adjusted for period end write downs/write backs); inventory (including natural gas inventory) is valued at the lower of cost and net realizable value; and regulatory assets and liabilities are unlikely to be recognized.

Under current practices both the income statement and the balance sheet record inventory at the Board approved reference price (WACOG) with any differences between WACOG and the acquisition cost of the commodity being recorded as a regulatory asset/liability.

B. Range of alternatives available

i. Alternative 1 – continue to use current practice to value inventories and cost of gas sold

The Board could choose to continue with the current practice of valuing gas inventories and cost of gas sold at WACOG and recording any differences in a regulatory account.

ii. Alternative 2 – value inventories and record cost of gas sold in accordance with IFRS

Alternatively, the Board could change the regulatory process so that inventories are valued at the lower of cost and net realizable value in accordance with IFRS, with the cost of gas sold and any write-downs and write-backs being recognized through the income statement.

A transitional adjustment may arise when applying the requirements of IFRS for the first time, which may need to be addressed by the Board.

iii. Alternative 3 – value inventories in accordance with IFRS but defer inventory write-downs and write-backs in a regulatory account; record cost of gas sold at acquisition cost

The Board could value inventories at the lower of cost and net realizable value and defer any resulting write-downs and write-backs in a regulatory account. The cost of gas sold would be recorded at acquisition cost but would not be adjusted for any inventory write-downs and write-backs.

A transitional adjustment may arise when applying the requirements of IFRS to inventory for the first time, which may need to be addressed by the Board.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

The current practice for valuing gas inventories at WACOG has the effect of smoothing rates. Variances resulting from actual gas prices that differ from WACOG are held in a regulatory account. In periods where prices are constantly changing, the effects of these variances are netted against each other in the regulatory account, resulting in a smoothing effect on rates. On a quarterly basis, rates are amended to recover/repay the variances. Therefore, over a period of time, ultimately determined by the Board, ratepayers bear the full cost of the commodity.

When inventories are valued at the lower of cost and net realizable value in accordance with IFRS, any write-downs will be recorded in earnings as they occur whether realized or not. If inventory has been written down to net realizable value and the net realizable value subsequently increases, the inventories will be written back up to their acquisition cost. In addition, the cost of gas sold will equal its actual acquisition cost during the period. If it were possible for the regulator to set rates based upon the costs recorded in earnings, ratepayers could see increased volatility in rates.

The Board could choose to value inventories at the lower of cost and net realizable value as required under IFRS and record all inventory write-downs and write-backs in a regulatory account. This alternative would reduce the volatility in the income statement, and therefore rates, as any adjustments in inventory values would be deferred. However, the effect of this may be offset by the fact that the cost of gas sold would be recorded at its acquisition cost and not stabilized through the use of WACOG.

In summary:

Alternative	Implications for rate payers
Continue to use current method	▪ Rate stability ▪ Smoothing of inventory variances in rates over time
Value inventories and cost of gas sold per IFRS	▪ Rate volatility ▪ No smoothing of inventory write-downs and write-backs in rates over time
Value inventories per IFRS but defer inventory write-downs and write-backs; record cost of gas sold at acquisition cost	▪ Rate volatility is reduced ▪ Smoothing of inventory write-downs and write-backs in rates over time

ii. Implications for utilities

If current inventory valuation methods are used for regulatory reporting then regulatory reporting will differ from financial reporting under IFRS, and may lead to the need for two sets of books, new internal controls and additional assurance requirements of the Board. However, established rate setting mechanisms and recovery processes are maintained.

If the regulatory requirements were changed so that inventories are valued at the lower of cost and net realizable value for both regulatory and financial reporting purposes with write-downs and write-backs recorded through the income statement, then the utility will be required to maintain inventory values on one basis eliminating the need to keep two sets of books. This alternative could, however, increase the volatility of a utility's earnings.

The regulator could require utilities to value inventories at the lower of cost and net realizable value with write-downs and write-backs recorded in a regulatory account instead of through the income statement. However, due to the difference in the accounting treatment of inventory write-downs and write-backs between general purpose financial statements and regulatory accounting, utilities would be required to maintain additional accounting records. This alternative would reduce the volatility in the income statement, and therefore rates, as any adjustments in inventory values would be deferred. However, the effect of this may be offset by the fact that the cost of gas sold would be recorded at its acquisition cost and not stabilized through the use of WACOG.

In summary:

Alternative	Implications for utilities
Continue to use current method	▪ Increased record keeping and internal control requirements ▪ Potential additional assurance
Value inventories and cost of gas sold per IFRS	▪ Financial and regulatory reporting are the same ▪ Volatility in earnings
Value inventories per IFRS but defer inventory write-downs and write-backs; record cost of gas sold at acquisition cost	▪ Increased record keeping and internal control requirements ▪ Increased accounting requirements ▪ Rate volatility may be reduced

iii. Implications for the rate-making process

No change will be required to established inventory valuation methodologies and current recovery mechanisms for price variances if the regulator chooses alternative 1. The regulator will have to decide whether additional audit assurance over inventory values and deferred price differences will be required. There will be a need to maintain formal procedures and guidance for inventory valuations and the calculation and treatment of price differences for use by the utilities.

If alternative 2 is chosen, then the rate setting mechanism will have to be revised. All inventory valuation adjustments and actual price differences from WACOG will flow through the income statement in the period incurred. Since inventory values for rate setting and financial reporting purposes will be the same, no additional assurance would be required.

The third option does not eliminate any of the implications noted in alternative 1 for the rate-making process. This option provides the tracking mechanism for the write-downs and write-backs but since the regulatory account is not recorded in the audited financial statements, additional assurance may be required. Since IFRS is not being followed for the treatment of write-downs and write-backs, formal procedures and guidance for use by the utilities will need to be developed and updated as necessary. Further, as the cost of gas would be recorded at its acquisition cost and not stabilized through the use of WACOG, a new or revised rate-setting mechanism would be required.

In summary:

Alternative	Implications for the rate making process
Continue to use current method	▪ Rate setting status quo is maintained ▪ Potential additional assurance ▪ Maintain and update procedures and guidance for inventory valuation and treatment of price variances
Value inventories and cost of gas sold per IFRS	▪ New or revised rate setting mechanism required ▪ No additional assurance
Value inventories per IFRS but defer inventory write-downs and write-backs; record cost of gas sold at acquisition cost	▪ New or revised rate setting mechanism required ▪ Potential additional assurance ▪ Maintain and update procedures and guidance for the treatment of regulatory accounts

5.1(b) Income Taxes and Payments in Lieu of Corporate Income Taxes (PILs)

This section addresses the question:

"What changes to existing regulatory accounting and rate treatments should the Board require for Payments in lieu of corporate income taxes?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Until January 1, 2009, utilities have recorded expenses for income taxes or payments in lieu of corporate income taxes ("PILs") using different accounting policies. Some record income taxes using the liability method prescribed under CGAAP and others record an estimate of the amount expected to be payable ("taxes payable" method). Under the taxes payable method, PILs are recorded based upon the amounts that are payable as determined by the current year tax filing.

Effective January 1, 2009, expenses for income taxes or PILs reported in general purpose financial statements will be determined via a two step process. Firstly, a utility will determine income taxes or PILs using the liability method. Under this method, in addition to the current expense for income taxes or PILs, future income taxes or PILs expense is recorded for the tax effect of temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes.

Secondly, the utility will make an assessment whether, as a result of an action by a regulator, future income taxes may be expected to be included in approved rates charged to customers in the future and to be recovered from or returned to future customers. To the extent this is the case, a utility would recognize an asset for that expected future revenue or a liability for that reduction in future revenue. Such an asset or liability is also a temporary difference for which a future income tax liability or asset is recognized; and presented separately from future income tax liabilities and future income tax assets. This assessment will clearly be dependent on the determination made by the regulator in setting future rates.

ii. Requirement under IFRS

For financial reporting purposes utilities will be required to record income taxes or PILs using the liability method as described above. However, as discussed in Section 2.1, if regulatory assets or liabilities are not recognized, then income taxes or PILs expense will not be adjusted for amounts expected to be recovered/returned to future customers.

iii. Summary of the accounting difference that will exist

After transition to IFRS, income tax expense or PILs expense, as reported in the income statement, will be recorded using the liability method.

B. Range of alternatives available

i. Alternative 1 – continue to use the current method to set rates

The Board could choose to continue with the current policy of allowing income taxes or PILs to be recovered in rates based on the estimated taxes using the allowed return on equity, plus or minus adjustments to arrive at forecast taxable income.

ii. Alternative 2 – use the liability method to set rates

Alternatively, the Board could choose to set rates based upon the liability method under which both current and future taxes are calculated.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

Continued use of the current method results in no change in the income taxes or PILs mechanism for ratepayers. Current ratepayers will bear the cost of income taxes or PILs based on the estimated taxes.

The liability method records income taxes or PILs expense on an accrual accounting basis so that reported expense includes an estimate of future taxes in addition to the current expense amount. If rates were set using this method there would likely be an impact for current ratepayers since current ratepayers will bear the cost of both current and future income taxes or PILs. The impact on rates will depend on each individual utility's tax position. This is a timing difference as the absolute amount of taxes paid over the life-cycle of any transaction remains unchanged (assuming, of course, no changes to actual tax rates over that time).

Adopting the liability method for the first time will result in a transition adjustment. For financial reporting purposes, the regulatory assets/liability associated with the future income tax expense, if any, will likely be de-recognised with an adjustment to opening retained earnings. The magnitude and directional impact on future rates is dependent upon the net tax position of each utility and the Board's decision as to how the transitional adjustment will be treated for rate making purposes recognizing that intergenerational equity issues will need to be considered.

In summary:

Alternative	Implications for rate payers
Current method	▪ Status quo maintained
Liability method	▪ Changes to timing of expense recognition ▪ Transitional adjustment to be addressed ▪ Intergenerational equity issues to be considered

ii. Implications for utilities

Utilities will need to follow the liability method for their general purpose financial statements. This may cause some utilities to change their accounting policies. Those entities that recognize regulatory deferral accounts for taxes in their general purpose financial statements will need to, at transition, derecognize any such amounts and in the future will likely find that income tax expense will be completely independent of the amounts recovered in rates.

If the Board were to allow the liability method to be used for rate-making purposes, then utilities would find that their income tax or PILs expense reported in general purpose financial statements would closely follow the amounts recovered in rates. The tax returns would be different.

The impact on the utilities at transition will depend on what the Board decides to do with any transition adjustments.

In summary:

Alternative	Implications for utilities
Current method	▪ No impact on amounts recovered
Liability method	▪ Financial and regulatory reporting are the same ▪ Timing of cash inflows and outflows will change ▪ Transitional adjustment to be addressed ▪ Intergenerational equity issues to be considered

iii. Implications for the rate-making process

Continued use of the current method will maintain the status quo for rate-making purposes.

Adopting the liability method will require the development of a new rate setting mechanism to deal with the recovery of both current and future income taxes or PILs. Procedures and guidance relating to the new mechanism will have to be developed and maintained. The Board would also need to address any transitional adjustments that will arise which would include the de-recognition of related regulatory deferral accounts.

In summary:

Alternative	Implications for the rate making process
Current method	▪ No change
Liability method	▪ New rate setting mechanism required ▪ Establish and update procedures and guidance for recovery mechanism ▪ Transitional adjustments to be addressed ▪ Intergenerational equity issues to be considered

5.1(c) Pensions and Employee Future Benefit Costs

This section addresses the following question:

"What changes to existing regulatory accounting and rate treatments should the Board require for pensions and employee future benefit costs?"

A. Relevant issue to be addressed upon transition to IFRS

i. Current requirement and practice under CGAAP

Pension and post employment benefits can be one of two types:

- Defined contribution plans; or
- Defined benefit plans.

In general purpose financial statements, these two types are accounted for differently. Expenses arising in connection with defined contribution plans are recorded in the income statement as contributions are made to a plan. Expenses arising in connection with a defined benefit plan are determined on an actuarial basis and are accrued.

In addition, current standards allow multi-employer defined benefit plans to be accounted for as defined contribution plans if an individual plan member company does not have the information to be able to account for the plan as a defined benefit plan. OMERS is an example of this.

There are a variety of accounting treatments for defined benefit post employment benefits currently being followed. Rates are usually determined based on the accounting treatment adopted in general purpose financial statements. The various treatments result in expenses being recognised on a:

- accrual basis: actuarial gains and losses recorded in income immediately;
- accrual basis: actuarial gains and losses recorded in income on a systematic basis with a minimum amount being amortised in any one year (the corridor method); or
- cash payable basis, i.e. in line with contributions to the plan

From January 1, 2009 changes to Section 1100 of the CICA Handbook will require that all utilities account for post employment benefits under CGAAP and then if they are recovering pension and employee future benefit costs on a non-CGAAP basis, they will adjust their income statement to reflect this and set up a regulatory asset or liability account where such accounts are authorised by the Board. Those utilities that currently determine post employment benefit expenses on a CGAAP basis should not be impacted.

In addition to the corridor method for recording actuarial gains and losses as described above, current CGAAP also provides for a number of smoothing mechanisms in connection with both the measurement and recognition of certain post employment benefits expenses as set out below.

Past service costs arising in connection with benefit plans that have been initiated or amended, and which are calculated by reference to an employee's past service, are allowed to be amortized to income over the average remaining service life of the employee group; or if employees are inactive, on a straight line basis over the average remaining life expectancy of the former employees.

The expected return on plan assets is allowed to be determined either at fair value or at a market-related value (i.e. value over a period not exceeding five years) of the plan assets. The use of market-related values smoothes out the effects of volatility in the expected return on plan assets.

ii. Requirement under IFRS

Under IFRS expenses arising in connection with defined contribution plans will continue to be expensed as contributions are made.

Under IFRS all defined benefit post employment benefits will be recorded on an accrual basis and will be actuarially determined.

Under IFRS a defined benefit multi-employer plan may be treated as a defined contribution plan if insufficient information is available for it to be accounted for as a defined benefit plan.

Utilities will have a number of choices to make on transition to IFRS. They can recalculate historical amounts following the IFRS rules or they can choose to make a one-time choice to recognize all cumulative actuarial gains and losses with an offsetting entry to retained earnings.

On an ongoing basis, utilities will have the choice of recording actuarial gains and losses as follows:

- In income immediately;
- Amortized to income on a systematic basis using the corridor method; or
- In equity immediately.

It should be noted, however, that changes to this IFRS standard are expected (see Section 6.1(d)) with the possibility that the choice to use the corridor method be removed.

Past service costs must be amortized over the vesting period. The vesting period is the period of time until the employee's right to receive the new benefit is no longer conditional on continued employment with the utility. If the past service costs are vested, then they are recognized immediately.

The expected return on plan assets must be determined at the fair value of plan assets at the beginning of the period.

iii. Summary of the accounting difference that will exist

The major differences between current CGAAP and IFRS in this area relate to the accounting for post employment arrangements that are considered to be defined benefit arrangements. As such, the alternatives discussed below consider only these differences.

Upon transition to IFRS, all utilities will have a one-time choice to recognize all cumulative actuarial gains and losses in full with an offsetting entry to retained earnings.

All utilities will continue to have options in recognising actuarial gains or losses.

Past service costs will have to be recognized over the vesting period rather than over the remaining service life of the employee group which will mean the recognition of expenses earlier than is currently the case.

The expected return on plan assets must be determined using fair value of plan assets at the beginning of a reporting period, which means that the actual benefit expense may be more volatile than is currently the case for those utilities that are currently using market-related values.

B. Range of alternatives available

i. Alternative 1 – set rates based on cash payable basis

The Board could set rates on the basis of cash paid.

ii. Alternative 2 – set rates based on IFRS without restrictions on accounting policy choices

Alternatively, the Board could require IFRS accounting for post employment benefits and pensions for all utilities where the cost of these plans is recognized in profit and loss as required by IFRS. The Board could allow the utility to determine its accounting policy choices (both on transition and on an on-going basis) and allow the resulting expense per the income statement to be used as the basis of rates.

iii. Alternative 3 – set rates based on IFRS but with restrictions on the accounting policy choices

The Board could also require IFRS basis of accounting as described in alternative 2, but would restrict the accounting policy choices both on an on-going basis and on transition.

The Board may, of course, wish to accept any one or all of these alternatives as a basis of setting rates.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

Setting rates based on cash paid means that rates will reflect the actual cash cost of a post employment arrangement. This may or may not be less volatile relative to a rate based on an actuarially determined expense.

The IFRS basis of accounting for post employment benefits results in the recognition of the costs incurred over the period in which the employee provides services to the utility. By removing some of the smoothing mechanisms, use of the IFRS basis of measurement and recognition may lead to more volatility in rates than under current CGAAP. Furthermore, allowing choices, on transition and with respect to the pattern of expense recognition going forward, may lead to inconsistency in the underlying basis on which rates are set. In particular, if a utility chooses to record all actuarial gains/losses immediately in equity, rather than recognising such amounts in the income statement, this will result in a different expense per the income statement relative, to a utility which elects to record such gains/losses in the income statement. This in turn may impact rates and the timing of recover of such costs.

Alternative 3 could have the same effect as alternative 2. However, the inconsistency among utilities in the underlying pattern of expense recognition would be removed as a result of the Board determining the fundamental policies that should be applied.

It would appear that adopting any one of the alternatives above could lead to a transitional adjustment for at least some utilities. This may impact future ratepayers depending on how this is addressed by the Board.

In summary:

Alternative	Implications for rate payers
Cash basis	▪ Cash costs of arrangements are funded ▪ Transitional adjustment to be addressed
IFRS without restrictions on the accounting policy choices	▪ Volatility in rates ▪ Inconsistent policies may be applied ▪ Transitional adjustment to be addressed
IFRS with restrictions on the accounting policy choices	▪ Volatility in rates ▪ Transitional adjustment to be addressed

ii. Implications for utilities

If the Board chooses to set rates on a cash paid basis, then this will lead to increased record keeping requirements for the utilities. Utilities will be required to maintain records that establish the full accrual cost of their post employment benefits for IFRS, as well as the cost of their post employment benefits as paid for rate setting purposes. This may not be particularly onerous. Internal controls will have to be established to ensure that the two sets of records are using the same information and that the regulatory amounts are complete and accurate.

In any one year, revenues to cover post employment benefits will not equate with reported expenses and therefore this will lead to volatility in reported earnings of a utility. (Revenues will, however, cover actual cash flows).

In addition, information submitted for regulatory purposes will not be the same as that reported in general purpose financial statements which have been subject to audit. The Board may therefore, require assurance regarding the costs submitted for rate setting.

Financial and regulatory reporting will be the same under alternative 2. This means that utilities will only have to maintain one set of records and these will be audited through the financial statement audit process. Reported expenses will match the reported revenues.

Alternative 3 could result in increased record keeping requirements for some utilities if they make different transition and accounting policy choices for general purpose financial reporting, to that required by the Board. Although this may not be particularly onerous, internal control processes may need to be amended. Additional costs may also be incurred if the Board requires assurance over amounts reported in rate applications that differ to those reported in general purpose financial statements.

It would appear that adopting any one of the alternatives above could lead to a transitional adjustment for at least some utilities. If this is not addressed by the Board, then utilities may incur a windfall gain/loss.

In summary:

Alternative	Implications for utilities
Cash basis	▪ Increased record keeping and internal control requirements ▪ Increased assurance requirements ▪ Volatility of reported earnings ▪ Transitional adjustment to be considered
IFRS without restrictions on the accounting policy choices	▪ Financial and regulatory reporting remains the same ▪ Revenues equal reported expenses ▪ Transitional adjustment to be considered
IFRS with restrictions on the accounting policy choices	▪ Financial and regulatory reporting may differ ▪ Possible volatility in reported earnings ▪ Transitional adjustment to be considered

iii. Implications for the rate-making process

It appears that current mechanisms allow rates to be set either on a cash basis or on an accrual basis. However, should the Board decide to change from current practices and mandate one or other basis then this will lead to some change in process for a number of individual utilities. This means that there will be some additional administrative burden, at least in the short term, as well as a possible need for additional assurance processes.

There are two main issues arising from the transition to IFRS. Firstly, there are accounting policy choices both on transition and on an on-going basis which fundamentally change the pattern of expense recognition. Secondly, smoothing mechanisms are likely going to be removed under IFRS. In the absence of such smoothing mechanisms the potential for significant volatility in rates exists as the accounting expense will be determined by, amongst other things, the expected return of fund assets at a particular point in time as well as market discount rates - factors which are outside the control of utilities.

In summary:

Alternative	Implications for the rate making process
Cash basis	▪ Possible need for additional assurance ▪ Establish and update procedures and guidance for the treatment of post employment benefits in rates ▪ Volatility in rates
Permit IFRS to be applied without restrictions on the accounting policy choices	▪ Volatility in rates ▪ Potential inconsistency across utilities
Permit IFRS to be applied but with restrictions on the accounting policy choices	▪ Volatility in rates ▪ Possible need for additional assurance

6. Decisions of Accounting Standard-Setting Bodies

6.1(a) Proposal for additional transitional exemptions for PP&E

This section addresses the following question:

"What are the potential implications on the Board's decisions of the potential exemption from the requirement for retrospective or fair value restatement of PP&E (International Accounting Standards Board)?"

A. Relevant issue to be addressed upon transition to IFRS

i. Matter that arises from current standards

As has been discussed in Section 3.1 on transition to IFRS, utilities will be required to reset the carrying value of their assets for general purpose financial reporting. There are currently two choices available to utilities to do this:

- reconstruct the carrying values of assets at transition "as if" IFRS accounting policies had always applied, with an adjustment to retained earnings; or
- determine the fair value of assets at transition (or an earlier date) and deem that value as cost. Any adjustment arising under this option would also be recorded in retained earnings.

Acknowledging the relative costs and benefits associated with applying either of the above options for rate-regulated entities the IASB is proposing to allow a third option on transition.

This third option may allow rate-regulated utilities to deem the carrying value of their assets at the date of transition to be cost under IFRS. If available, this would avoid the need to either reconstruct carrying values in accordance with IFRS or determine their fair value.

If this third option was available, this would be relevant in determining an appropriate policy response to the question considered under Section 3.1 earlier in this report. If a utility was permitted to continue to retain its carrying values at the date of transition, and, on the basis the regulator required entities to continue to use existing NBV for rate setting, this may eliminate relevant transitional adjustments.

This is a transitional exemption only. Immediately after transition, a utility is required to account for its assets under IFRS. Therefore the discussion of the accounting differences as set out in Section 3, continues to be relevant.

ii. Status of proposed exemption

In September 2008, the IASB issued an Exposure Draft ("ED") containing the proposal. The deadline for comments closed on January 23, 2009. Over 90 comment letters were received by the IASB. Responses are mixed and a number of clarifications have been requested. It is unclear as to whether the proposed exemption will be allowed or amended. It is expected that the IASB will finalize this matter during the second half of 2009.

If the exemption is available, then the interaction with other transitional exemptions will also need to be considered by the IASB; namely: borrowing costs and transfers of assets. The relevant impacts of these requirements have been considered in Section 3.4.

B. Range of alternatives available to the Board

Given the above uncertainty, we believe the Board has three choices as follows:

i. Alternative 1 – Determine policy response, in absence of IASB decision

The Board could press ahead with its current plans and determine its policy choice on transition in the absence of the IASB decision. This decision would be made after considering the implications of IFRS on opening rate base as considered in Section 3.1.

By making its final decision, the Board would remove any uncertainty for all stakeholders, accepting that this may come at a cost (depending on the alternative chosen) and that it may not be the most optimal decision which minimizes transition costs (should the proposed exemption be confirmed).

However, depending on the decision that is then later made by the IASB, utilities may end up having to maintain two sets of books, develop additional internal controls, and face the possibility of additional assurance requirements.

ii. Alternative 2 – Determine policy - re-visit on final IASB decision

Although making an interim decision might not fully remove all the uncertainty that currently exists, the Board's initial views would at least have been communicated. Making an interim decision, for example to indicate that current rate base will not be changed upon adoption of IFRS, would provide the industry with some guidance on the way forward. Utilities and Board staff would then be in a position to advance some aspects of their IFRS projects based on this initial understanding and develop a strategy and/or contingency plan for possible changes.

iii. Alternative 3 – wait for an IASB decision before proceeding

Given that the decision regarding the opening rate base value and the treatment of any transitional adjustments is an important one for all stakeholders, the Board has the option to wait until the IASB makes a final decision on the proposed exemption.

The timing of a final IASB decision is, however, uncertain therefore one impact of this option is to delay the start of other important phases of the Board's IFRS project (i.e. developing and updating of the Board's regulatory instruments, training of Board staff and stakeholders, etc). The transition date to IFRS has been confirmed as January 2011 and this is unlikely to be amended.

6.1(b) IASB's proposed project on rate-regulated accounting

This section addresses the following question:

"What are the potential implications on the Board's decisions of the proposed IASB project on rate–regulated accounting, e.g., the recognition of deferral and variance accounts?"

A. Relevant issue to be addressed by accounting standard-setting bodies

i. Matter that arises from current standards

As discussed in Section 2.1 of this report, unlike CGAAP, IFRS does not have a standard or any guidance that addresses rate-regulated accounting and general IFRS practice is not to recognise regulatory assets and liabilities in general purpose financial statements.

In December 2008, however, the IASB agreed that it would develop an IFRS on rate-regulated activities.

It is proposed that the project will focus on cost-of-service or other forms of regulation according to which an entity has a right to recover all or part of its costs and to earn a specified return (or has an obligation to refund all or part of excess profits) through future rate adjustments. The project would not address price-cap regulations that only consist of a price setting mechanism with no "guarantee" that the entity will recover its costs plus a specified return.

It is unclear, however, as to how any future requirements will be applied by utilities. We expect that this project will lead to some sort of change in financial reporting requirements under IFRS.

The outcome of this IASB project is therefore particularly relevant to the decisions currently facing the Board with respect to whether or not it will continue to use deferral and variance accounts in setting rates despite the fact that the economic effects of such accounts may not be reflected in audited general purpose financial statements. The implications of this on the various stakeholders are discussed in section 2.1 of this report.

ii. Status of IASB project

The IASB is proposing that an Exposure Draft ("ED") setting out its proposed requirements for rate regulated activities will be issued in May 2009. The IASB has indicated that this is an ambitious target date. At the IASB meeting recently held in February 2008, IASB staff confirmed that they are continuing to work quickly on this matter and will shortly be moving onto the recognition and measurement issues.

B. Range of alternatives available

Given the above uncertainty, we believe the Board has three choices as follows:

i. Alternative 1 – Determine policy response, in absence of IASB decision

The Board could press ahead with its current plans and decide whether or not deferral and variance accounts should continue to be used for rate setting purposes in the absence of the IASB decision. This Board decision would be made after considering the implications of IFRS on all stakeholders as considered in Section 2.1.

By making its final decision, the Board would remove any uncertainty for all stakeholders, accepting that the decision taken may not be the most optimal one, that, minimizes on going compliance costs should the IASB subsequently determine an accounting model that is acceptable for rate making purposes.

ii. Alternative 2 – Determine policy based on ED – revisit on final standard

As the IASB intends to issue an ED in May 2009, it may be possible for the Board to use the ED to determine a likely outcome for the IFRS project. The Board could then make an interim decision based on this.

Although making an interim decision might not fully remove all of the uncertainty that currently exists, the Board's initial views would at least have been communicated. Making such an interim decision would provide the industry with some guidance on the way forward. Utilities and Board staff would then be in a position to advance some aspects of their IFRS projects based on this initial understanding and develop a strategy and/or contingency plan for possible changes.

iii. Alternative 3 – wait for an IASB decision before proceeding

Given that the decision regarding how rate regulated activities should be accounted for is an important one for all stakeholders, the Board has the option to wait until the IASB issues its standard before making a decision.

The issuance of a final IASB standard is, however, not something that can realistically be expected in the short term.

6.1(c) Adoption of IFRS by government business enterprises

This section addresses the following question:

"What are the potential implications on the Board's decisions of the uncertainty relating to whether accounting standards will require municipal and provincial government-owned distributors (government business enterprises) to adopt IFRS (Public Sector Accounting Board – Canada)?"

A. Relevant issue to be addressed by accounting standard-setting bodies

i. Matter that arises from current standards

This matter relates to most, but not all, of the utilities regulated by the Board. Those utilities that have issued publicly traded debt instruments will be required to report to securities authorities using IFRS irrespective of the possible changes in reporting requirements under the Public Sector Accounting Handbook ("PSAH").

In Canada, the Public Sector Accounting Board ("PSAB") establishes generally accepted accounting principles for governments and government organizations, including government business enterprises ("GBEs") and government business-type organizations ("GBTOs"). Generally, GBEs currently follow CGAAP for profit-oriented enterprises.

Prior to November 2008, PSAB had directed GBEs and GBTOs to adopt IFRS in 2011. However, as a result of concerns PSAB decided to re-evaluate the decision. The outcome of this re-evaluation is still pending.

This means that most of the utilities (i.e. those that are owned by government and which do not issue publicly traded debt instruments) subject to rate regulation by the Board may not be required to transition to IFRS at all but will instead be subject to a different set of accounting requirements which may or may not be the same as current CGAAP.

ii. Status of PSAB decision

Re-deliberation of this issue commenced at the January 2009 meeting of the PSAB. The PSAB issued an Invitation to Comment ("ITC") on 24 February 2009 seeking additional input from all its stakeholders.

The ITC is based on existing definitions of all government organization types and it does not propose to revisit these definitions. The existing definitions of Government Business Enterprises ("GBEs"), Government business –type organisation ("GBTOs") or government not-for-profit organizations ("GNFPOs") are included in the ITC. Other government organizations ("OGOs") will continue to be defined as those government organizations that are not GBEs, GBTOs or GNFPOs.

The ITC is seeking views on the breadth of the application of IFRS to GBEs and GBTOs given that the CICA Handbook-Accounting will no longer exist in its current form post January 1, 2011. The ITC proposes to allow other government OGOs to select the most appropriate source of GAAP, either IFRS or the Public Sector Accounting (PSA) Handbook.

The ITC raises four alternatives as set out below. These alternatives result in applying IFRS to:

(1) Those government organisations that are a "publicly accountable enterprise" as proposed by the AcSB;

(2) GBEs as defined by PSAB;

(3) The same types of organisations as defined by the IPSASB; or

(4) All GBEs and only those GBTOs as defined by PSAB that are competing with similar entities outside of the public sector that also follow IFRS.

The following table compares the source of GAAP for each government organisation type under each of the proposed alternatives.

<table>
<tr><th></th><th>Current requirement</th><th>Alternative 1</th><th>Alternative 2</th><th>Alternative 3</th><th>Alternative 4</th></tr>
<tr><td rowspan="2">GBEs</td><td rowspan="2">IFRSs</td><td>Publicly accountable – IFRSs</td><td rowspan="2">IFRSs</td><td rowspan="2">IFRSs</td><td rowspan="2">IFRSs</td></tr>
<tr><td>Remainder – Self-selection*</td></tr>
<tr><td rowspan="2">GBTOs</td><td rowspan="2">IFRSs</td><td>Publicly accountable – IFRSs</td><td rowspan="2">Self-selection*</td><td>Self-sustaining – IFRSs</td><td>Private sector competitor – IFRSs</td></tr>
<tr><td>Remainder – Self-selection*</td><td>Remainder – Self-selection*</td><td>Remainder – Self-selection*</td></tr>
<tr><td>GNFPOs</td><td colspan="5">Under review in a separate AcSB/PSAB ITC</td></tr>
<tr><td>OGOs</td><td colspan="5">Self-selection*</td></tr>
</table>

*PSAH or can elect to apply IFRSs

An outcome that determines that utilities should use the PSAH would result in fundamentally different financial reporting relative to CGAAP. This would have implications for rate making.

B. Range of alternatives available

Given the above uncertainty, we believe the Board has three choices as follows:

i. Alternative 1 – Determine policy response, in absence of PSAB decision

The Board could determine policy that impacts all utilities prior to the final decision by PSAB. If PSAB later determines that IFRS will not be required for GBEs and GBTOs, and instead imposes another accounting framework, then it is possible that such policy decisions may need to be revisited. Such utilities are therefore currently facing two sources of fundamental uncertainty:

- what accounting framework will they be required to report under post 2011; and
- what regulatory requirements will be relevant post 2011.

This option does not remove any of that uncertainty because the Board may need to revisit its policy which was initially determined on the assumption that an IFRS reporting framework would be required.

ii. Alternative 2 – Determine policy based on ITC - re-visit when PSAB makes final decision

It may be considered that the ITC provides sufficient certainty for the Board to make its policy determinations albeit on an interim basis.

Although making an interim decision might not fully remove all the uncertainty that currently exists, the Board's initial views would at least have been communicated. Making such an interim decision would provide the industry with some guidance on the way forward. Utilities and Board staff would then be in a position to advance some aspects of their IFRS projects based on this initial understanding and develop a strategy and/or contingency plan for possible changes.

iii. Alternative 3 – wait for a PSAB decision before proceeding

The Board's decision to change policy is a response to changes to the underlying reporting requirements faced by utilities. Therefore some may argue that until the required reporting framework is known, it is impossible to determine a final policy response.

The Board is faced with a difficult decision. It knows with certainty the required reporting framework for at least some utilities. Other utilities may end up with either a prescribed reporting framework or they may have a choice. Either way, the Board will be faced with uncertainty in reaching its decision.

6.1(d) Other developments from accounting standard-setting bodies

This section addresses the following question:

"What are the potential implications on the Board's decisions of the uncertainty relating to other developments from accounting standard-setting bodies?"

There are a number of other developments arising from both the Canadian accounting standard-setters and the IASB not yet covered in this report but which may be relevant to the Board as it considers its policy response to changing accounting requirements. Set out below is a brief summary of the current and likely developments that we believe are of most relevance to the Board, with a brief discussion as to possible impacts.

A. Canadian Accounting Standards Board ("AcSB") developments

In this section we discuss the recent amendments to CICA Handbook Section 1100 for rate regulated entities. Other recent developments from the AcSB relate to intangibles and inventories, which are covered in Section 3 and 4 of this report respectively.

In December 2007 the CICA revised the Handbook to remove a temporary exemption from the requirements in Handbook Section 1100 for rate regulated entities. Whilst the general exemption was removed, an exemption and associated guidance was retained for rate-regulated entities in four specific areas relating to consolidation accounting, accounting for AFUDC, accounting for income taxes and accounting for gains and losses on the disposition of assets. These changes are effective for fiscal periods beginning on or after January 1, 2009.

We believe that, for financial reporting periods prior to transition to IFRS, many regulated entities will attempt to build an argument that, following the GAAP hierarchy, they can look to U.S. GAAP for guidance. Such guidance may be found in US Statement of Financial Accounting Standards No. 71 (SFAS 71), *Accounting for the effects of certain types of regulation*,and the related FASB pronouncements. If the entities are successful in making this argument, we further believe that this will mean that entities that wish to record regulatory assets and liabilities will need to first do their accounting under the requirements of CGAAP (including the remaining special provisions for regulated entities should they apply). Then, to the extent that the rate actions of a regulator provide reasonable assurance of the existence of an asset or liability, the income statement may be adjusted and a regulatory asset or liability may be recorded.

At this point the effect that this will have on financial reporting under CGAAP is uncertain. We understand that many entities believe that they will be able to develop appropriate arguments that will support the continued recording of regulatory assets and liabilities, albeit through a two-step approach rather than a one step approach. We also expect that some entities may not qualify.

B. IASB developments

The IASB has an extensive work plan which will lead both to amendments to existing IFRS as well as to the development of new IFRS standards. The extent of future change is significant and raises a number of issues for the Board to consider as follows.

Firstly, a number of either amended standards or new standards are likely to be issued prior to the transition date of January 1, 2011. It is possible that the IASB will allow these new requirements to be early adopted if an entity so chooses. Upon transition to IFRS, a utility may wish to early adopt these new requirements in order to ease the conversion effort or for other reasons. This means that if the Board requires information to be reported consistently from the date of transition of IFRS then it may consider:

(i) mandating the option to apply the new requirements,

(ii) removing the option to apply the new requirements, or

(iii) requiring additional explanation of the impact of applying the new requirements.

Secondly, both the new requirements that are being considered and the major projects on the work plan may lead to fundamental changes in financial reporting. For example the project examining the IFRS Conceptual Framework is fundamental to the basis on which all IFRS standards are developed. The Board should therefore continue to monitor IASB developments and be prepared to consider further policy changes should that be required.

A copy of the IASB work plan, along with the projected timetable is included as Appendix B to this report.

7. Rate Impact

7.1 Not used

7.2 Mechanism to Mitigate Rate Impacts

This section addresses the following question:

"Should a mechanism be developed to phase-in or otherwise mitigate the rate impacts, if any, of adopting IFRS (e.g. one-time transition charge or other provision)?"

A. Relevant issue to be addressed upon transition to IFRS

i. The Impact of IFRS on costs and hence rates

The implementation of IFRS may have an impact on rates through a variety of mechanisms:

- Relative to existing practice, IFRS may shift, on a go forward-basis, the classification of costs from capital to operating accounts, or vice versa. This will affect the profile of rates in a regulated utility environment, since operating costs are generally recovered in the period concerned, while costs allocated to capital are recovered over the life of the associated asset.

- The process of implementing and maintaining general purpose financial statements that are consistent with IFRS may directly increase actual utility expenditures in the short term, and possibly also in the long-term, and thus ultimately increase the costs that utilities seek to recover from rate payers. This simply reflects the administrative burden associated with IFRS accounting changes and procedures.

- IFRS could also result in one-time transition adjustments that could shift rates, in addition to just changing their profile over time. For example, IFRS may allow or require utilities to restate the value of their capital assets (either to reflect Fair value or to remove costs that are not eligible to be capitalized under IFRS). If the Board allowed utilities to earn a return on any increase in value, then rates will be adjusted upward. Conversely, rates could fall if the value of assets is adjusted downward.

Incentive Regulation blurs the link between a utility's reported financial expenses and its rates, but does not eliminate it. During the term of an incentive regime, rates are set using a standard indexing formula that takes prior period rates and adjusts them for expected changes in costs. This suspends the direct link between costs and revenues for a period of time. In the rebasing year, however, rates are reset based on forecast or allowed financial expenses in that year. Changes in reported expenses as a result of IFRS can thus flow through to customers. In our discussion of the impact of IFRS on reported costs, and hence rates, we have generally ignored the fact that Incentive Regulation may result in a lag between changes in reported cost and changes in utility rates. This simplifies the discussion while not distorting the long-run impacts.

The nature of rate mitigation required may depend on the actual magnitude and direction of the impact of IFRS on costs. Calls for mitigation often result when there is a large percentage increase in rates, which may also be referred to as "rate shock". As noted above, operating expenses could suddenly increase because IFRS reduces the costs that can be allocated to capital. Costs then appear on one year, rather than being spread over the life of an asset. This increase in costs is temporary and is a matter of timing. (A temporary increase occurs because consumers initially pay upfront for current period costs that would have been capitalized in the past, but they still bear amortization charges reflecting costs that actually were capitalized in the past. It is a matter of timing because the costs capitalized in the past would have been recovered over the life of the asset. In the same way, rates in later years may actually be lower than they would have been without IFRS, as a result of the shift in the timing of cost recognition. In addition, capitalized costs attract a regulated return as a result of being included in the rate base and this tends to push up rates further in later years in a scenario in which such costs are capitalized.)

Of course, IFRS will generally only affect rates if the Board accepts IFRS definitions of cost for rate setting purposes. If the Board requires utilities to continue to report cost using current CGAAP standards, then IFRS implementation will generally not affect measured costs and hence rates. (The one exception is that the very implementation of IFRS may increase utility operating costs and the method of recovery of these costs will need to be determined.) As discussed elsewhere in this report, using current accounting standards for rate setting purposes, while using IFRS for financial reporting purposes, will result in two sets of books and, hence, some additional complexity and cost. The Board will also need to address the fact that

CGAAP will no longer exist post transition to IFRS. This may require the Board to maintain or develop separate reporting requirements which may or may not affect costs/rates.

ii. Approaches to mitigation

Mitigation could entail limiting the percentage increase in rates, or the amount of increase in rates, that occurs in one period as a result of any shift in the timing of costs. To ensure that utility shareholders are protected, however, any costs that are thus not recovered in one period will have to be recovered in a later period. Thus, rate mitigation may effectively result in a deferral account. Rate mitigation will then serve to smooth out the increase in rates, but will not eliminate it.

Mitigation approaches could also be used to limit decreases in rates, if such a decrease is an outcome of the transition to IFRS. Stakeholders, however, are generally less concerned about rate decreases and this will tend to reduce the support for mitigation measures in such a scenario.

If costs increase on an ongoing basis, perhaps because the implementation of IFRS itself serves to increase utility costs going forward (moving them permanently to a higher level), rate mitigation strategies are more problematic. Any deferral of costs will magnify the increase in costs in later years, when deferred costs must be added to the increased cost base.

As noted above, IFRS could also result in a restatement of the value of the existing asset base of a utility. If the revised asset base is used to set capital charges (depreciation plus return on capital) for the utility, this will result in either a "windfall" gain or loss to utility shareholders, in addition to a one-time change in the level of rates (and thus "rate shock") for customers. Regulators are typically unwilling to allow such windfall gains or losses to accrue to shareholders in a regulated utility environment. Such an outcome would be perceived as breaking the "regulatory compact", which suggests that shareholders will recover all prudently incurred costs and, in turn, consumers will pay no more than these costs.

To facilitate a restatement of utility asset value under IFRS but avoid windfall gains or losses to shareholders, a regulator could make an offsetting adjustment in the rate setting process. Under this scenario, the regulator would recognize the change in asset value, but then also apply an offsetting change to the utility's Revenue Requirement in the period of the restatement. Thus, if the utility asset base was increased in value by $10 million, there would be an offsetting reduction in allowed revenues in the period such that utility earnings in that period fall by $10 million relative to a scenario in which there was no revenue reduction. As a result, retained earnings would remain unchanged relative to a scenario in which IFRS had not been implemented. Future capital charges (depreciation plus return on capital) for the utility would be higher, reflecting the adjusted asset base, but shareholders would have "paid" for this enhanced revenue stream going forward by taking a one-time revenue reduction. This could result in a substantial decrease in rates in one period. Alternatively, the revenue reduction could be divided over a number of periods (to smooth out the variation in rates across periods). This would require creating a deferred liability for rate setting purposes only. This liability would be used to smooth out the effect of the required one-time rate reduction.

The advantage of the overall approach outlined in the prior paragraph is that it would allow the rate base to be consistent with IFRS, without resulting in wind-fall gains or losses to the shareholder. However, it would result in significant additional complexity in the short term relative to maintaining existing asset values, and result in rate fluctuations that do not reflect any change in the underlying economics of the business. Rate changes attributable to accounting policy changes may be difficult to explain and justify to stakeholders.

In summary, strategies for mitigation:

- Can help to smooth the impact of IFRS on rate payers.
- Will result in some additional complexity in rate setting and associated administrative burden on both the Board and the utility.
- Would need to be clearly defined prior to their implementation.

7.3 Rate Increase Thresholds

This section addresses the following question:

"Should rate increase thresholds be set?"

We interpret this question to mean:

"If a rate mitigation method is adopted as discussed in Section 7.2, should it be implemented only for those utilities for which the transition to IFRS would increase reported period expenses, and thus rates, by more than a threshold amount?"

A. Relevant issue to be addressed upon transition to IFRS

The rationale for setting a rate increase threshold could be that it results in implementation of the mitigation mechanism only in those cases where there is a significant impact on utility rates. A threshold thus helps to minimize the administrative burden associated with operation of the mitigation mechanism, by restricting it to those circumstances in which mitigation is clearly needed.

Potential disadvantages of a rate increase threshold are as follows:

- It results in variation across utilities in the approach to implementing IFRS and in translating changes in reported cost to changes in rates.
- Some additional complexity will result from the need to define how the threshold will be defined and implemented. For example, IFRS may have different impacts on reported expenses, relative to CGAAP, depending on the period chosen for comparison.

A number of additional issues must be taken into account in evaluating this mechanism:

- In any given rebasing year (which is when changes associated with IFRS could potentially have an impact on rates), rates may change as a result of a variety of impacts, only some of which are related to IFRS. In addition to the impacts on measured costs as a result of IFRS, rates may change because of underlying changes in a utility's capital base, in its operating expenses, and through changes in allowed rates of return. Since these various changes may or may not have offsetting impacts, there is some logic to considering mitigation approaches, and associated thresholds, taking into account overall changes in rates from all impacts considered together. Thus, it may be appropriate to have an overall threshold, and not just one related to IFRS impacts.

- Rate impacts from IFRS may be different for different customer classes. Thus, the Board would need to define whether the threshold is applied to a measure of average rates overall, or rates for each customer class individually.

8. Utility and Shareholder Impact

8.1 Recovery of transition costs

8.2 On-going compliance costs

This section addresses the following questions:

"Should the costs (e.g. new systems, special audits, consulting) to transition to IFRS be recovered from ratepayers? On what basis?"

and

"Should incremental on-going compliance costs be recovered from ratepayers? On what basis (z-factor treatment? threshold amounts?)?"

A. Relevant issue to be addressed upon transition to IFRS

i. Costs expected to arise on transition to IFRS

As an initial step, it is worth considering the types of costs that may be incurred during the transition to IFRS and on an ongoing basis. Whilst it is impossible to be definitive and provide an exhaustive list of these costs, it is fair to say that the initial conversion costs are likely to be of the following nature:

- Additional costs for internal resources;
- External consulting fees on technical accounting matters;
- External consulting fees regarding IT systems and process changes;
- IT development costs;
- Training costs; and
- Additional one-off audit fees for the audit of the restated opening balance sheet (ie the transition adjustments) and the 2010 comparatives.

Such costs may be incurred directly or may be allocated to a utility by its corporate parent.

In addition, there will likely be significant post-transition compliance costs including multiple reporting requirements or books of record, additional financial reporting and disclosure requirements, additional operational requirements and additional assurance costs. Such assurance costs may also include fees for providing assurance to the Board of the legitimacy of regulatory accounts outside of the scope of general purpose financial statements prepared using IFRS. These costs are incremental to current cost levels, and would be incurred annually in order to maintain compliance.

ii. Principles with respect to the recovery of utility costs

To address the question of whether IFRS costs should be recovered from ratepayers, it is worth considering the principles that generally apply to the recovery of utility costs.

Regulators typically allow utilities to recover all of those costs that are prudently incurred and that are necessary to provide services to customers. In this context, regulators have, from time to time, disallowed certain types of costs. For example, the Board's 2006 EDR rate-setting process provided that the following types of costs were not eligible for inclusion in a utility's Revenue Requirement:

- Advertising expenses incurred for the primary purpose of promoting corporate branding or image.
- Political contributions in the form of donations to political parties.
- Charitable contributions other than to programs that provide assistance to distributors' customers in paying their electricity bills.
- Annual fees or dues for employee memberships in organizations that are recreational or social in nature. (Dues related primarily to health and fitness were recoverable provided that they covered programs generally available to all employees.)

Other types of expenditures may be subject to review, and allowed for inclusion only if their benefit to ratepayers is clear. For example, the 2006 EDR Handbook required utilities to demonstrate that any research and development expenditures were intended to benefit utility ratepayers.

The market restructuring process also provides some precedents with respect to the types of costs that may be disallowed. In its guidance with respect to the recovery of transition costs, the Board noted:

"Transition cost related to corporate reorganization and to the transfer by-law whereby the municipal corporation acquires the assets of the municipal electricity distribution utility will not be recovered in rates." (Page 5-5, Ontario Energy Board Electricity Distribution Rate Handbook - Revised, June 16th, 2000)

This document also noted: "Transition costs should be directly related to operational requirements created by industry restructuring."

iii. Principles considered in the context of IFRS transition

With respect to costs associated both with the transition to IFRS as well as the on-going incremental costs that may arise as a consequence of the transition to IFRS, we note the following:

- For any utility that is mandated to implement IFRS, the associated transition costs are not discretionary but are in response to an external mandate.
- It is not clear that the transition to IFRS is exclusively or even primarily for the benefit of utility shareholders.

Regulators can disallow a portion of any cost that has not been prudently incurred. Thus, a utility that does properly control expenditures can have a portion of these expenditures removed from its Revenue Requirement.

iv. Mechanisms for recovery of costs

The Board may need to allow utilities to set up a deferral account to accumulate the costs of IFRS conversion. This is particularly true for costs incurred during periods in which rates have already been set based on an earlier cost of service application or through use of an IRM indexing formula. The deferral account could accumulate IFRS costs for later recovery in the event that such costs were not included in the cost base upon which existing rates were set.

If a deferral account is established, a related question is to what extent IFRS conversion costs should be subject to review prior to collection from rate payers. Tests could be similar to those applied to costs subject to recovery through the Z-factor mechanism. These tests are as follows:

- **Causation.** Amounts should be clearly outside the base upon which rates were derived.

- **Materiality.** The amounts must exceed the Board defined materiality threshold and have a significant influence on the operation of the utility; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.

- **Prudence.** The amount must be prudently incurred. This means that the utility decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The tests for Z-factor recovery are relatively stringent. In its recent report on 3rd Generation IR, the Board noted: "The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations." (Reference: p. VI, Appendix: Filing Guidelines, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008.)

B. Range of alternatives available

i. Alternative 1 – Recover all IFRS costs from rate payers as a cost of service

The Board could choose to allow utilities to recover all of their one time IFRS conversion and incremental compliance costs from ratepayers. This may be immediately on transition or over time via a phase-in mechanism.

ii. Alternative 2 – Capitalize IFRS conversion costs and recover them through return on rate base

The Board could choose to allow utilities to include conversion costs in their rate base calculation, and thus recover the costs through their return on rate base and through amortization of the capitalized amount. Under this alternative, the on-going compliance costs could still be recovered through the annual operating expense allowance.

iii. Alternative 3 – Do not recover IFRS costs from ratepayers

The Board could choose not to allow IFRS costs to be included in cost of service.

iv. Alternative 4 – Recover a portion of IFRS costs from ratepayers

The Board could choose to allow only a portion of IFRS costs to be recovered from ratepayers through operating costs. This may be all or part of the incurred costs to make the transition, and all or part of the on-going incremental costs. The rationale for recovering only a portion of these costs from ratepayers would need to be considered.

C. Implications of the alternatives on rate-making

i. Implications for rate payers

If the Board allows all IFRS conversion and on-going costs to be recovered from ratepayers as a cost of service, then there will be an increase in rates in proportion to the associated cost increases.

If the Board allows the utilities to include conversion costs as a part of their rate base, then ratepayers will pay for conversion costs over time. The length of time over which costs will be recovered will depend on the length of time over which these capitalized costs are amortized. This approach will smooth the impact on rates from the recovery of IFRS conversion costs.

If the Board does not allow IFRS conversion and on-going costs to be recovered from ratepayers, then rates will not be impacted by IFRS, even though the utilities incurred costs to perform the transition process and maintain compliance.

If the Board allows only a portion of the IFRS conversion and on-going costs to be recovered from ratepayers, then ratepayers will not feel the full impact of the conversion costs on their rates, but would still see some rise in rates as a result of the conversion.

In summary:

Alternative	Implications for the rate payers
Recover as cost of service	▪ Rates increase immediately or over time
Recover as rate base	▪ Rates increase, and include an element of return
Do not recover	▪ Rates remain unchanged
Partial recovery	▪ Rates rise, but do not cover the total costs

ii. Implications for regulated utilities

If the Board allows all IFRS conversion costs to be recovered from ratepayers as a cost of service immediately, then the utilities will not bear any of the conversion costs. If costs are phased in over time, this may affect utilities' cash flow, and would be a reconciling item between the rate submission and IFRS financial statements.

If the Board allows all IFRS conversion costs to be recovered from ratepayers through rate base, then utilities will be compensated for the costs of conversion over a period of time. During the period of the recovery, utilities would earn a return on outstanding amounts equal to their allowed cost of capital. Additionally, since these conversion costs would likely not meet the IFRS definition of an asset, these conversion costs will become a reconciling item between the rate submission and IFRS financial statements.

If the Board did not allow IFRS conversion costs to be recovered from ratepayers, then the utility's shareholders would be forced to fully absorb the costs of the conversion.

If the Board allows only a portion of the IFRS conversion costs to be recovered from ratepayers, then utility shareholders will bear part of the burden of these conversion costs.

In summary:

Alternative	Implications for utilities
Recover as cost of service	▪ Utility is not forced to bear the cost
Recover as rate base	▪ Utility is not forced to bear the cost ▪ Utility revenue increases
Do not recover	▪ Utility shareholders are forced to bear cost
Partial recovery	▪ Utility bears some of the cost

iii. Implications for the rate-making process

If the Board allows all IFRS conversion costs to be recovered from ratepayers, either as an immediate cost of service or through the rate base, then the Board may be required to review the conversion costs in detail to ensure they were reasonable.

If the Board does not allow all IFRS conversion costs to be recovered from ratepayers, then it will have to review general and administrative costs submitted as part of a rate setting process to determine which costs are not to be recovered.

If the Board allows only a portion of the IFRS conversion costs to be recovered from ratepayers, then it will need to determine the basis by which such costs would be included. For example:

The Board could choose to place a dollar value limit on the conversion costs to be spent. This would provide cost certainty to the ratepayers, and would prevent utilities from bearing the entire burden of the conversion costs. Establishing a dollar limit that was fair and equitable may prove challenging given the potential variability in the cost, and the fact that limits would need to be calculated on a utility by utility basis. Under this regime, shareholders would bear only costs that are above the specified threshold. If the threshold was set to cover the expected or "reasonable" costs of IFRS conversion, then the rationale for having shareholders bear any excess could be that such costs reflect "unreasonable" cost overruns. The cost of conversion, however, may vary significantly across utilities, because of differences in legacy accounting systems, in the timing of conversion, and in their ability to draw on other resources. Differences in conversion cost may not just reflect management effectiveness. Establishing a fair threshold would thus be difficult.

The Board could establish a fixed percentage of IFRS costs that would be recoverable in rates. By making shareholders bear a fixed proportion of costs, then utilities would have a clear incentive to minimize these costs. However, from a fairness perspective, there would also need to be a clear rationale as to why shareholders should bear a proportion of IFRS costs.

In summary:

Alternative	Implications for the rate making process
Recover as cost of service	▪ Board would need to review cost for reasonableness
Recover as rate base	▪ Board would need to review cost for reasonableness
Do not recover	▪ Board would need to review general and administration costs to determine what would be disallowed
Partial recovery	▪ Board would need to establish the basis for inclusion in rates ▪ Difficult to administer and monitor

8.3 Cost minimization

This section addresses the following question:

"How can the Board encourage minimization of IFRS implementation costs?"

A. Relevant issue to be addressed upon transition to IFRS

i. Implication of IFRS

As discussed in Sections 8.1 and 8.2, the transition to IFRS will lead to increased costs for the utilities both during the initial conversion, and through ongoing incremental costs. It would be in the best interests of all parties involved for the utilities to focus on keeping the implementation costs as low as possible, while still complying with both regulatory and statutory reporting requirements

B. Possible Options

Set out below are some strategies that the Board may wish to consider in order to contain the costs incurred by the industry as a result of transitioning to IFRS. These suggestions are not meant to represent an exhaustive list, but are meant to provide a foundation for further discussion on cost minimization.

- The Board could facilitate sharing of information and collaboration among utilities on a voluntary basis. For example, the Board could sponsor working groups with utility participants to examine issues involved in the transition to IFRS. This will facilitate the sharing of information and the development of common solutions to issues. Participation in these groups could be purely voluntary, and utilities would have full discretion in determining the extent to which they would adopt any materials or approaches developed. The appropriateness of this type of support strategy will depend, in part, on the Board's views with respect to its role and mandate.

- The Board could issue guidelines on the accounting policies that utilities adopt for reporting to the Board. These guidelines could be consistent with IFRS, but more restrictive. They could therefore reduce the need for utilities to make their own individual decisions about accounting polices if they simply wish to follow the Board's guidance for both their audited financial statements and their reporting to the Board. Guidelines could be provided in an "IFRS Handbook" that would be issued by the Board.

- The Board could state the manner in which it will require financial information to be reported to the Board. The Board guidance could include descriptions of circumstances or policies that differ from IFRS. This would provide utilities with clarity as to the information needed. It would allow them maximum flexibility in determining how to minimize any differences arising from IFRS and how to reconcile any such differences. In contrast to the suggestion above, this option would allow the Board to specify policies that fall outside of IFRS.

- The Board can sponsor projects to collect information that will assist utilities in meeting the requirements of IFRS.

- The Board could sponsor depreciation studies that would provide updated information on the useful lives of assets for Ontario utilities. (This alternative was discussed earlier in Section 4).

- So as to minimize the expenditures on the IFRS conversion, the Board may wish to consider how much relief is appropriate to grant in rates. Thus, for example, the Board could establish a dollar or percentage threshold for the recoverability of IFRS costs. Any costs incurred by the utilities above this threshold would not be recovered through rate submissions. This limit would not directly reduce the costs of transition or compliance, but would provide an additional incentive for the utilities to reduce their IFRS related costs.

To the extent that the Board imposes, within the boundaries of IFRS, specific policies on utilities for financial reporting, the following impacts may result:

- The Board could increase its ability to make comparisons across utilities, since financial information will be more consistent.

- Individual utilities ability to make accounting decisions that reflect their specific circumstances may be compromised. Thus, for example:

  - Asset lives determined through a province-wide study may not reflect experience in an individual utility jurisdiction, since climate and topography, as well as individual utility operating practice, may affect expected asset lifespan.

  - Appropriate approaches to recognizing asset components may differ, for example, across utilities of different sizes. Attempts to impose a common approach may impair the accuracy of financial statements.

Difficult questions also arise with respect to those utilities not affected by IFRS. It is possible that some utilities may not be required to adopt IFRS for financial reporting purposes on or after January 1, 2011. (Refer discussion in section 6.1(c)). For these utilities, an obvious cost minimization strategy would be to allow them to continue to report to the Board using their existing accounting policies. However, this approach will increase the inconsistency in financial reporting across utilities and may make it more difficult, for example, for the Board to compare utilities' financial performance.

9. Filing Guidelines for Rate Applications

10. Electricity Distributor and Gas Utility Reporting and Record-Keeping Requirements

Section F (Filing and Reporting Requirements) of the Board's Issues List contains a number of questions, the responses to which can only be determined after changes to rate making policy are known. Our comments are therefore limited and identify some matters that specifically arise as a consequence of the transition to IFRS.

A. Key reporting matters that may arise

During the period of transition

The conversion to IFRSs involves more than just assessing the impact of different accounting frameworks on a utility's financial report. It is a complex project that may impact IT systems and controls and key business processes such as planning and budgeting. It may involve a significant training effort and may also affect business arrangements.

Given the potential scope of impact of the transition to IFRS, as well as the interest that the transition is likely to generate, the Board may wish to request specific information from regulated utilities during the period leading up to 2011. We note that the Canadian Securities Administrators ("CSA") requires certain qualitative and quantitative disclosures from publicly listed entities only.

After transition to IFRS

As has been discussed elsewhere in this report, IFRS contains a number of accounting policy choices. Choices made by one utility may not be the same as those made by another. This may, therefore, impact upon the process for, and usefulness of, the financial information obtained from utilities. Under CGAAP, uniform reporting requirements are achieved through the use of the Uniform System of Accounts ("USoA") that is developed and maintained by the Board. Through use of the USoA, the Board is currently able to obtain financial data with the utilities and:

a) Understand each utility's financial and regulatory performance; and

b) Benchmark utilities for purposes of comparative analysis.

This may need to be modified after transition to IFRS.

B. Reconciliations

It is expected that some differences will exist between general purpose financial statements and regulatory accounts. Utilities will likely need to prepare some form of reconciliation between general purpose financial statements and the information used in the rate making process. It will be important to consider the extent and magnitude of the differences that may arise, any potential significant up-front investment in IT solutions, any potential ongoing recurring cost burden for the utilities and whether or not required reconciliations can be sustained in the long run without significant negative effects on the rate making process.

Furthermore, rate filings require three years of information (Historical, Bridge and Test years). As a result of the change in the basis of accounting upon transition to IFRS, it is possible that certain rate applications during the transition period may use information prepared on different accounting bases which may require further reconciliation.

Reconciliation requirements are not, however, without precedent. Our research has indicated that a number of the overseas electricity industry regulators prescribe accounting treatments for rate setting purposes which are different to those used to prepare general purpose financial statements. In such instances, utilities are required to maintain separate accounting information for regulatory purposes.

C. Timing of the transition to IFRS

The Canadian Accounting Standards Board allows utilities to early-adopt IFRS. Some utilities may wish to early adopt the new requirements to ease the conversion effort or for other reasons. Therefore, the Board may wish to either restrict or mandate such early adoption to ensure a consistent basis of reporting.

We note that another Canadian regulator, Office of the Superintendent of Financial Institutions Canada ("OSFI") has specifically prohibited the early adoption of IFRS by its regulated entities due to the significant impacts that early adoption would have otherwise had on their organization. It determined that the changes that needed to be made to their systems, regulatory returns and instructions as well as agreed industry protocols required some time before they could be implemented.

D. Assurance requirements

The extent of additional assurance requirements will vary with the extent of differences between IFRS general purpose financial statements and the financial information reported to the Board for rate-making purposes. The Board may determine that the rate filings should be subject to additional assurance. Our research has indicated that some regulators specifically require an audit of regulatory accounts.

If the Board decides to require independent assurance over regulatory accounting values, the supplementary assurance could take different forms. There are three main choices available:

- Full audit of financial information submitted with the rate filing in accordance with CICA Handbook Section 5805;
- Performance of specified procedures as determined by the Board and reported in accordance with CICA Handbook Section 9100; and
- Audit of internal controls over financial reporting in accordance with CICA Handbook Section 5925 or agreed upon procedures regarding internal controls over financial reporting in accordance with CICA Handbook section 9110.

Full audit

A full audit of the financial information submitted with the rate filing would require an auditor to express an opinion on the financial information in accordance with a predetermined standard such as guidance issued by the Board. The audit opinion would cover whether or not the financial information is presented fairly in accordance with the basis of accounting that had been determined by the Board. This option provides the Board with the highest level of audit assurance over the financial information provided for purposes of setting rates.

Specified procedures

A specified procedures report in accordance with Section 9100 of the CICA Handbook is not an audit, and an audit opinion is not expressed. The Board would develop a set of procedures which would be directed at obtaining assurance over specified information provided to the Board in utility rate filings. Auditors would perform the procedures that are developed by the Board and would then report their findings. Any errors found will be described, quantified and reported allowing the assessment of the impact on rates.

Procedures relating to internal controls over financial reporting

Audit in accordance with CICA Handbook Section 5925

An audit of internal controls over financial reporting provides assurance regarding the effectiveness of the utility's internal controls over financial reporting processes. An audit in accordance with CICA Handbook Section 5925 may be integrated with the audit of the utility's general purpose financial statements. Management of the utility would initially make an assessment of the utility's internal controls over financial reporting and then the auditor would express an opinion on the effectiveness of those internal controls.

This form of assurance does not provide assurance over the balances reported in the financial information but rather gives reasonable assurance over the reliability of financial reporting and preparation of the financial information provided in the rate filing in accordance with the basis of accounting established by the Board for rate filing purposes.

Agreed-upon procedures in accordance with CICA Handbook Section 9110

An agreed-upon procedures report on internal controls over financial reporting is not an audit, and an audit opinion is not expressed. The auditor performs an agreed set of specific procedures regarding internal controls and reports the results without expressing any opinion. These results will be included in the report for the users of the report to make their own assessment of, and to draw their own conclusions on, the design, implementation or operating effectiveness of the internal controls over the utility's financial reporting.

Section B

1. IFRS experiences in other similar regulatory jurisdictions

1.1 Purpose and objectives

In order for the Board Consultation to benefit from the experiences of other economic regulators that have already transitioned to IFRS, KPMG was requested by the Board to identify and explore two regulatory jurisdictions, if any, which have transitioned to IFRS and have a comparable basis of economic regulation as Ontario, Canada.

The particular circumstances that the Board sought to identify were:

- Jurisdictions that have a basis for establishing consumer prices for regulated commodities that is comparable to the basis used by the OEB, and where that jurisdiction has made a transition to IFRS. The commodities in question were natural gas (not gasoline/petrol) and electricity, but in some jurisdictions could include water;
- From among those jurisdictions that use a comparable basis for price regulation, the Board sought to identify any economic regulatory regimes wherein the regulated entities have completed a transition to IFRS from some form of non-IFRS basis of GAAP; and
- By "comparable basis of economic regulation" the Board meant any basis for setting prices that depends in a significant way on the values recorded in the books of account of the regulated entity as a reference point when the regulator determines just and reasonable rates for consumers.

1.2 Process followed to identify similar jurisdictions

The following process was followed in order to identify the regulatory jurisdictions that have a comparable basis of economic regulation as Ontario, Canada:

- KPMG Canada developed a high-level questionnaire setting out the specific questions that were considered important in order to make a comparison of the extent of similarities and differences amongst the various economic regulatory regimes; and

- The high-level questionnaire was distributed to pre-selected offices of the various member firms within the KPMG global network.

It is important to note the following:

a) By participating in the voluntary exercise, the participants assumed no responsibility whatsoever to the users of this report;

b) Although the KPMG staff members that participated have ongoing working knowledge of the economic regulatory regimes in their particular regulatory jurisdictions, they are not economic regulation experts or specialists. Participants were only required to have working knowledge, experience and/or understanding of the activities of commodity economic regulators and the related impact of IFRS in their regulatory regimes.

1.3 Countries included

KPMG member offices, existing in the following countries that have already adopted IFRS, were included:

a) Australia

b) Belgium

c) France

d) Germany

e) Italy

f) Israel

g) New Zealand

h) Russia

i) Spain

j) Sweden

k) Switzerland

l) Great Britain (England, Scotland and Wales)

At the time of completing this report, the following countries had not completed the questionnaire: France, Germany and Spain. For this reason, the key findings that are set out below do not include information relating to these three countries.

1.4 Key findings

Our research identified the following key points:

a) Method for determining rates

The electricity and natural gas industries in all the above countries are subject to economic regulation. In all instances, the economic regulators determine rates either on a cost of service model or an incentive model (i.e. often CPI – X) that is designed to give an efficient operator an adequate rate of return, together with some additional incentives.

b) Adoption of IFRS by regulated entities

Although IFRS has been adopted in preparing general purpose financial statements by listed public companies in the above-mentioned countries, utilities in most of the jurisdictions are not required to apply IFRS in their separate "stand-alone" general purpose financial statements or in reporting to the economic regulator. Local GAAP is still widely used in the "stand-alone" general purpose financial statements of many utilities. Australia and Israel are exceptions to this, and require regulated utilities to report in accordance with IFRS in their general purpose financial statements.

In Israel, however, although IFRS has been adopted by the regulated utility, it has been granted permission to continue applying the US Statement of Financial Accounting Standards No. 71 (SFAS 71), *Accounting for the effects of certain types of regulation*, to its regulated operations. As a result, regulatory assets and liabilities continue to be recognized in the general purpose financial statements. The audit report is, however, amended to reflect the resulting non-compliance with the specific requirements of IFRS.

As utilities in most countries continue to report in accordance with their respective local GAAP for both regulatory purposes and general purpose financial statements, issues relating to the transition to IFRS did not arise.

c) Use of regulatory accounts

Most of the regulators require regulated entities to prepare a second set of financial statements, ("regulatory accounts").

In the UK, for example, these regulatory accounts are mostly prepared on a local UK GAAP basis, but have the same content and format as general purpose financial statements, where possible.

Where regulatory accounts are required, the majority of the respondents indicated that their regulators require these accounts to be audited.

d) Preparation of detailed regulatory accounting guidelines

Detailed regulatory accounting guidelines, which must be applied in all tariff regulations (including rate applications), exist in most jurisdictions. While these may be based on local GAAP, they also include specific provisions which, where relevant, take precedence over local GAAP. We note that, for example, the regulator in Belgium prescribes the depreciation rates for property, plant and equipment.

We noted examples of rate applications being supported by additional financial and other information, including for example, detailed investment plans and other forecasts. Examples of regulatory accounts being further supplemented by detailed and extensive cost analysis information in a prescribed format were also noted.

e) Regulatory accounting

As more fully detailed in Section 2.1, regulatory assets and liabilities are generally not recognized under IFRS. We noted however that utilities in Belgium recognize regulatory liabilities in their IFRS general purpose financial statements. We understand that local Belgium GAAP is used for rate setting purposes and that this allows for the recognition of both regulatory assets and liabilities.

Appendix A – Acronyms used in the report

APH	Accounting Procedures Handbook issued, updated and maintained by the Ontario Energy Board for use by Hydro utilities in applying CGAAP
CGAAP	Canadian Generally Accepted Accounting Principles as set out in the current CICA Handbook
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards as issued by the IASB
RSVA	Retail Settlement Variance Accounts
OEFC	Ontario Electricity Financial Corporation
FAQ	Frequently Asked Questions
WACOG	Weighted Average Cost of Gas

Appendix B – IASB work plan as at 25 January 2009

IASB Work Plan

projected timetable as at 25 January 2009

The timetable shows the current best estimate of document publication dates. The effective date of amendments and new standards is usually 6-18 months after publication date, although in setting an effective date the Board considers all relevant factors. In appropriate circumstances, early adoption of new standards will be allowed.

The work plan anticipates the completion of several projects in 2010 and 2011. The Board will consider staggering effective dates of standards to help entities that apply IFRSs undertake an orderly transition to any new requirements.

The Board undertakes this work using its established due process, including consultation with interested parties. The timetable for completion is subject to change depending on input received throughout a project's development.

Abbreviations

AD	Agenda Decision (to add the topic to the active agenda)	**AG**	Advisory Group
CG	Completed Guidance	**DP**	Discussion Paper
ED	Exposure Draft	**IFRS**	International Financial Reporting Standard
RT	Roundtables	**TBD**	To be determined

New standards and major projects	**Last document issued**	**Estimated publication date**					**Estimated publication of final document**	**IASB-FASB Collaboration**	
		2009 Q1	**2009 Q2**	**2009 H2**	**2010 H1**	**2010 H2**		MoU[1]	Joint[2]
Common control transactions							TBD		
Consolidation	ED	RT		IFRS				✓	✓
Derecognition		ED		IFRS				✓	✓
Emissions trading schemes				ED	IFRS				✓
Fair value measurement guidance	DP	ED	RT		IFRS			✓	
Financial instruments (replacement of existing standards)	DP	AG					TBD	✓	✓
Financial instruments with characteristics of equity	DP			ED			2011	✓	✓
Financial statement presentation	DP				ED		2011	✓	✓
Government grants[3]							TBD		
IFRS for private entities	ED		IFRS						
Income taxes		ED			IFRS			✓	✓
Insurance contracts	DP			ED			2011		✓
Leases		DP			ED		2011	✓	✓
Liabilities[4]	ED			IFRS					
Management commentary	DP		ED		CG				
Post-employment benefits (eg pensions)	DP			ED			2011	✓	
Rate-regulated activities			ED				TBD		
Revenue recognition	DP				ED		2011	✓	✓

Footnotes

1. These projects are part of the Memorandum of Understanding that sets out the milestones that the FASB and the IASB have agreed to achieve in order to demonstrate standard-setting convergence.
2. These projects are being undertaken with the FASB. Even though *joint ventures* and *post-employment benefits* are not being undertaken with the FASB, in each case the IASB has committed to improve the related IFRSs.
3. Work on this project has been suspended.
4. The project on *liabilities* deals with proposed amendments to IAS 37.

IASB Work Plan – continued

Amendments to standards	Last document issued	Estimated publication date					Estimated publication of final document	IASB-FASB Collaboration	
		2009 Q1	2009 Q2	2009 H2	2010 H1	2010 H2		MoU	Joint
Annual improvements 2007-2009	ED		IFRS						
Annual improvements 2008-2010				ED	IFRS				
Discontinued operations (IFRS 5)	ED		IFRS						✓
Earnings per share (IAS 33)	ED			IFRS					✓
Embedded derivatives (IAS 39/IFRIC 9)	ED	IFRS							
Financial instruments: enhanced disclosures (IFRS 7)	ED	IFRS							
First-time adoption of IFRSs (IFRS 1): additional exemptions	ED			IFRS					
Joint ventures	ED		IFRS					✓	
Related party disclosures (IAS 24)	ED			IFRS					
Share-based payment: group cash-settled transactions (IFRS 2 and IFRIC 11)	ED		IFRS						
Conceptual Framework[5]									
Phase A: Objective and qualitative characteristics	ED		Final chapter						✓
Phase B: Elements and recognition					DP		TBD		✓
Phase C: Measurement				DP		ED	TBD		✓
Phase D: Reporting entity	DP			ED			TBD		✓
Phase E: Presentation and disclosure									✓
Phase F: Purpose and status									✓
Phase G: Application to not-for-profit entities									✓
Phase H: Remaining issues									✓
Research									
Extractive activities		DP					TBD		
Intangible assets[6]							TBD		

Footnotes

5. The IASB and the FASB will amend sections of their conceptual frameworks as they complete individual phases of the project.
6. In December 2007 the IASB decided not to add this project to its active agenda. National standard setters are carrying out research for a possible future project. The Australian Accounting Standards Board has published a discussion paper *Initial Accounting for Internally Generated Intangible Assets*.