EB-2016-0160

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. Transmission with the Ontario Energy Board on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018;

OEB PROCEEDING EB-2016-0160

APPLICATION BY HYDRO ONE NETWORKS INC. FOR APPROVAL OF TRANSMISSION REVENUE REQUIREMENT

BOOK OF AUTHORITIES OF HYDRO ONE NETWORKS INC.

January 12, 2017

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<u>**INDEX**</u>

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Ontario

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook
for
Utility Rate Applications

October 13, 2016

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates. Rates are the key revenue tool for regulated utilities. Under legislation, regulated natural gas utilities and electricity distributors, transmitters and Ontario Power Generation (OPG)[1] are only permitted to charge for their regulated services through an order issued by the OEB. In making an order, the OEB must set rates or payments that are just and reasonable.

This Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications. The Handbook is applicable to all rate regulated utilities[2], including electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. It has been developed based on the OEB's policies and the experience gained through the processing of rate applications since the release of the *Renewed Regulatory Framework for Electricity* (RRFE)[3]. The OEB expects utilities to file rate applications consistent with this Handbook unless a utility can demonstrate a strong rationale for departing from it.

The Handbook contains the following sections:

- Background on the Renewed Regulatory Framework
- Legislative Mandate and Test
- Rate Applications and the Adjudicative Process
- The OEB's Review of the Key Components of Rate Applications
- Rate-Setting Options
- Rate-Setting Policies

[1] OPG is the only generator subject to rate regulation by the OEB.
[2] This Handbook uses the term "utilities" to refer to all rate regulated entities unless specified otherwise.
[3] *Board Report: Renewed Regulatory Framework for Electricity Distributors,* October 18, 2012 (RRFE Report)

2. Background on the Renewed Regulatory Framework

The OEB established a new framework for electricity distribution rate regulation in 2012. The *Renewed Regulatory Framework for Electricity* is a foundational policy: it articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities. Key principles of the RRFE include the expectation for continuous improvement, robust integrated planning and asset management that paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

The OEB set out its goals for the RRFE as follows:

> The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.[4]

An important aspect of the RRFE is the evolution to an outcomes-based approach. The OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."[5] There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:

- Customer Focus: Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.

[4] RRFE Report, p. 1.
[5] RRFE Report, p. 2.

- Operational Effectiveness: Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

- Public Policy Responsiveness: Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First[6] in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low income customers through programs such as LEAP and/or OESP[7], or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement. Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program.

- Financial Performance: Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.

[6] Conservation First is a government policy referred to in the Long-Term Energy Plan.

[7] Low Income Energy Assistance Program (LEAP) and Ontario Electricity Support Program (OESP).

Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation).

Since the release of the RRFE Report, over half of Ontario electricity distributors have applied for rates under the RRFE. Enbridge Gas Distribution Inc. also applied using the principles of the RRFE. Based on its review of those rate applications, the OEB has now completed an assessment of the RRFE and the principles underpinning it. This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the *Renewed Regulatory Framework* (RRF) in this document and by the OEB going forward to reflect this transition.

3. Legislative Mandate and Test

The foundation for the OEB's public interest mandate is the *Ontario Energy Board Act, 1998*. The OEB Act sets out the objectives for the OEB's regulation of natural gas and electricity. The OEB balances these objectives in order to protect consumers, set demanding but fair performance expectations for utilities, facilitate the evolution of the sector, and support the policies of the Ontario government.

The OEB's authority to set rates for electricity distribution, transmission and payments for OPG[8] is set out in section 78 of the OEB Act. The key test is that the rates or payments must be "just and reasonable." The OEB reviews the information and proposals in a rate application in order to determine whether the proposals are reasonable for both consumers and the utility. For natural gas, the OEB's authority to set just and reasonable rates is in section 36 of the OEB Act.[9]

For all regulated utilities, the onus is on the utility to demonstrate that its rate (or payment amount) proposals are just and reasonable. If the OEB determines that the proposals are not just and reasonable, then it may set other rates (or payment amounts) which it determines are just and reasonable.

[8] For OPG, Ontario Regulation 53/05 also defines the OEB's authority.
[9] Details of the legislative provisions are set out at Appendix 1.

4. Rate Applications and the Adjudicative Process

This Handbook applies specifically to rate applications, under any of the legislative sections identified above, which are intended to set rates for a multi-year period (Custom IR), or for the first year of a multi-year period (Price Cap IR or Revenue Cap IR). Under the RRF there are a variety of incentive rate-setting (IR) options which are discussed further in section 6 (Rate-Setting Options).

A comprehensive rate application has three main components: the business plan (along with supporting documentation and reports), historical and forecast information, and rate models that show the derivation of specific proposed rates based on the data.

- Business plan: The utility's plan for its business is foundational to the proposals included in its rate application. This includes the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them. The OEB expects the business plan to be informed by the utility's engagement with customers. The business plan is supplemented and supported by the associated plans, reports and documentation (including system plans[10], capital and operational plans, programs, benchmarking, external reviews, and customer engagement activities) which form the core of the rate application. This utility business plan may differ from the corporate business plan that may include matters that go beyond the scope of the OEB's review in a rate application.

- Historical and forecast information: Information filed in support of a rate application facilitates a thorough review of the utility's proposals and ensures continuity in the regulation of each utility over time. The filing of this information does not mean that the OEB will approve every aspect of what is filed in a rate application. The OEB assesses the utility's plans, and the resultant costs and revenue requirement, in order to consider the benefits to customers and a fair return for utilities in setting just and reasonable rates.

[10] The term "system plan" is used in this Rate Handbook to refer generically to all types of plans that apply to the various sectors; that is "distribution system plan" for electricity and natural gas distributors, "transmission system plan" for electricity transmitters, and any nuclear and hydro-electric generation asset plan that OPG may file in the future.

- Rate models: The OEB has developed a set of rate models for electricity distributors which facilitates the review of rate applications and which distributors are required to use. These models are one of the tools the OEB uses to enhance the efficiency, consistency and accuracy of the review process.

To assist utilities, the OEB has developed filing requirements that identify the information that needs to be provided in an application. There are separate filing requirements for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. The OEB expects utilities to present rate applications that are complete and of high quality. A rate application is complete if it contains all of the information (data, reports and analysis) that the OEB has identified in the filing requirements. In addition to meeting the requirements from the filing requirements, high quality rate applications also address all of the regulatory policy considerations relevant to the company in a comprehensive, consistent and clear presentation that articulates the need for the utility's proposals and the value to customers.

In the past, the OEB used the regulatory process itself to augment a deficient application to ensure the information was complete and consistent. This approach added complexity and time to the process, increasing regulatory costs. In recent years, the OEB has conducted initial reviews of applications for completeness, to ensure that only applications which are substantially complete are allowed to proceed. A rate application must demonstrate on its face that it is of sufficient quality to support the OEB's rigorous review process. An application that does not meet this standard will not be processed; it will be returned for further work. This is one of the ways the OEB will ensure that utilities take full ownership of all aspects of the information and proposals included in their applications.

The OEB uses an open and transparent adjudicative process to review rate applications. The adjudicative process can involve a number of steps, depending on the type of application, to ensure that a utility's proposals are adequately examined and "tested" during the review. (Potential tools include interrogatories, technical and settlement conferences, and an oral hearing). The review involves stakeholders, including customer representatives and other groups. OEB staff ensures that the views of customers are considered in the application process by organizing community meetings to gather consumer views on the utility's proposals, using different media to notify customers that an application has been filed and facilitating the filing of letters of comment to the OEB from customers. The OEB is further augmenting its processes through the Consumer Engagement Framework to ensure customers have a stronger voice in the adjudicative process. The OEB uses the adjudicative process to ensure its review results in just and reasonable rates for customers. The OEB's approach to reviewing utility proposals within rate applications is discussed in the remaining sections of this Handbook.

5. The OEB's Review of the Key Components of Rate Applications

One of the OEB's primary goals is to ensure that utilities are delivering cost effective, efficient, reliable and responsive services to customers. The RRF is intended to elevate utility performance by creating incentives for superior performance. The RRF focuses on increased effectiveness and continuous improvement in meeting customer needs, including cost control and system reliability and quality objectives.

A utility's proposals are expected to demonstrate the alignment of the utility's strategic objectives with its current and future customers' expectations for reliable and reasonably priced service. The utility is expected to integrate its business challenges, and what its customers are saying, to create a compelling business plan that directly links to proposals included in the rate application and the four performance outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance. In reviewing utility proposals, the OEB will analyze past performance but is even more concerned with future performance. The Ontario energy sector has gone through significant change, and even more change is expected in the future, particularly technology-driven change which has the potential to deliver significant benefits to customers.

The OEB will use a variety of tools to aid its review work, including trend analysis, cost benefit analysis, reviews of distributor due diligence processes (planning, risk management, governance, etc.), benchmarking and other analytical tools. The OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility's spending proposals. If the OEB determines that a specific project or program has not been adequately justified, this may result in a reduction to the requested revenue requirement. It is the utility's responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements, within the funding provided through rates. This provides the utility with the responsibility and flexibility to meet its obligations in ways which benefit customers and the utility.

In reviewing utility proposals in rate applications, the OEB's key considerations are:

- **A focus on cost effective delivery of outcomes that matter to customers**
- **Robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risks**
- **Performance assessments which analyze the level of continuous improvement and a utility's ability to plan and execute plans**

The following key components are addressed in this section:

- Business plan
- Customer engagement
- Planning
- Outcomes and performance metrics
- Performance scorecards
- Benchmarking
- Operations, Maintenance and Administration (OM&A) and Compensation Expenses
- Bill Impacts
- Mergers, Acquisitions, Amalgamations and Divestitures (MAADs)
- Non-Regulated Activities and Affiliate Transactions

Business Plan

A utility's business plan for its regulated activities is fundamental to the evaluation of the proposals in its rate application. The business plan (which is included in the Executive Summary of the application) should describe the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the rate application and the plan to meet them, and how customers will benefit. It forms the "story" that underpins the rate application as a whole and its constituent parts. The business plan should address the utility's circumstances and challenges, integrate its customers' expectations, set performance commitments, and demonstrate how the results will be achieved. This business plan is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews and customer engagement) which form the core of the rate application.

The business plan should demonstrate that the utility's goals are appropriately aligned with the needs and preferences of its customers and the objectives of the RRF, and that the utility is well positioned to deliver on its goals. This information will allow the OEB to understand the impacts of the business plan on key areas of the application such as customer service, system reliability, costs and customer bills.

In reviewing a utility's proposals in a rate application, the OEB will consider whether the business plan demonstrates how the utility's objectives are:

- **Translated into outcomes**
- **Relate to what is being sought in the application**
- **Align with the objectives of the RRF**
- **Align with customer preferences and expectations**

Customer Engagement

Customer engagement is foundational to the RRF. Enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. Today's customers are more informed and more active participants in their energy services. They should have a say in shaping utility plans, particularly given the customer's role in conservation efforts and the customer-focused nature of future technological innovation. Customers should also help determine the pace of utility investment.

Each type of utility will have a variety of customers to include in engagement activities. For example, natural gas utilities have end-use customers and transportation customers. Electricity distributors have end-use customers, generators, and sometimes other embedded distributors. Electricity transmitters have customers which are distributors, generators, and large end-use customers. Ontario Power Generation has an indirect relationship with end-use customers. Although the types of customers vary, the principles presented here are applicable to all utilities. The OEB expects utilities to adapt these principles to their particular circumstances.

Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate those interests and preferences into their plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs. Existing processes and customer interactions should also inform the customer focus element of the utility's proposals. For example, reliability complaints could inform investment program priorities, such as targeting poor performing feeders for upgrades, or the use of smart grid technology to reduce the duration of outages.

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities. The application must also demonstrate how the utility has reflected customer input in the development of its plans. The OEB will evaluate whether the utility's application is reflective of, and appropriately informed by, customer needs, expectations and preferences and whether the utility is positioned to deliver on its plans in a way that will provide value to customers.

In reviewing customer engagement, the OEB will consider:

- **The forms of customer engagement used, their quality and effectiveness**
- **The quality of the utility's analysis of customer input**
- **Whether and how customer input has informed the utility's planning**
- **Whether and how the utility's plans deliver benefits which address customer needs and preferences**

The OEB is not specifying how customer engagement should be done or how customer feedback should be received. It can take many forms, and the OEB expects utilities to consider a range of approaches, using both existing and new processes. A customer satisfaction survey is a tool to gauge how a customer views the past performance of its utility, but it is not a tool that engages customers on future plans and therefore is not sufficient to meet the OEB's expectations for appropriate engagement to inform the utility's plans. Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity. The OEB will consider the adequacy of customer engagement in assessing whether it has been demonstrated that a proposal provides value to customers. If the OEB determines that customer engagement has not been adequate, then the OEB may conclude that a program or project is not adequately justified, in whole or in part, and this could result in a reduction to the requested revenue requirement.

Planning

Robust planning is one of the foundations of the OEB's RRF. The utility's business plan sets the context for the proposals in a rate application (as part of the Executive Summary of the application). The utility's system plan is an important component of the application and complements and supports the specific capital and operational plans and programs, and the associated budgets, which form the utility's overall business plan.

A utility's core business in serving customers is asset management, and strong asset management is essential to delivering reliable and quality energy services that customers value. Strong planning will help drive operational effectiveness, and the utility system plan will be an important component of the utility's business plan which supports the rate application. The capital intensive nature of the energy sector and long life of most assets means that investment brings with it the likelihood of rising costs as aging and fully depreciated assets are replaced with new assets. Therefore it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates. Utilities are expected to develop plans that deliver lower cost solutions over the long-term through a Conservation First approach, integration with regional plans, and consideration of the evolution of the sector, including innovation and new technologies. Utilities are expected to engage customers and incorporate their expectations into their planning.

The OEB's comprehensive policies for electricity distributor system planning, and filing requirements are set out in *Chapter 5 of the Filing Requirements for Electricity Rate Applications*. The planning principles, as set out in the next section, are applicable to all rate-regulated utilities. However, other utilities (natural gas utilities, electricity transmitters, and OPG) would include different types of initiatives in their plans. For example, a natural gas utility would need to incorporate the cap and trade program in its system plan. The discussion below is presented in the context of electricity distribution system plans, but is intended to provide guidance to electricity transmitters, natural gas utilities, and OPG.

Electricity Distribution System Plans

The OEB requires electricity distributors to file a distribution system plan (DSP) every five years, regardless of the rate-setting method chosen. The DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The asset management process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus. The asset management process needs to be informed by an asset condition assessment such as equipment testing results, maintenance and usage history, historical failures or system weaknesses. Information is also required on the consequences of the failure of assets (such as how many customers will be affected, the type of customers and the time to restore the system) to appropriately prioritize plans. The capital expenditure plan sets out and justifies a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance and operations expenditures.

A DSP must contain sufficient information to allow the OEB to assess whether and how a distributor has planned to deliver value to customers, how the plan supports the effective management of the assets, and how a distributor is seeking to control the costs and related rate impacts of proposed investments. The asset management plan underpinning the DSP should be directly linked to the proposed budget, to demonstrate that the proposed capital expenditures have been determined through the necessary optimization and prioritization process.

The OEB has consolidated, streamlined, and strengthened its planning policies into an integrated approach. Under this integrated approach, all network investments will be planned together, including network renewal and expansion, connection of renewable generation facilities, smart grid development and implementation, conservation, and investments arising from regional planning processes.

The DSP is expected to have the following characteristics:

- Consolidated and stand-alone (i.e. not presented through separate parts across an application)
- Includes all assets, both system assets and general plant
- Underpinned by an asset condition assessment
- Linked directly to the proposed budget
- Integrates considerations of conservation, smart grid, renewable generation connection, regional planning, and any relevant public policies
- Demonstrates how the utility has planned to deliver value to current and future customers
- Demonstrates how the plan supports the effective management of the assets
- Demonstrates how the plan is optimized (by considering alternatives, including different capital program options, maintenance or operating solutions, the use of conservation to defer investments, the use of new and emerging technologies, etc.) and how projects are prioritized and paced to recognize potential rate impacts

In a cost of service proceeding the OEB will consider the entire five year DSP as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the DSP. The OEB has established a policy for the funding of capital for electricity distributors on the Price Cap IR option.[11] Requests for funding under these mechanisms must meet all of the same requirements for capital spending

[11] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

as would be in a cost of service or Custom IR application. Any Incremental Capital Module that involves a significant increase to a capital budget may need to be supported by a DSP along with customer engagement analysis.

In reviewing the utility system plan, the OEB will consider the following:

- **Have the criteria outlined in Chapter 5 of the *Filing Requirements for Electricity Rate Applications* been addressed?**
- **Does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and corresponding capital and operational plans and budgets?**
- **How has the plan addressed the information and preferences gathered from the utility's customer engagement work?**
- **Does the plan deliver quantifiable benefits for customers?**
- **Does the plan support the achievement of the utility's identified outcomes, and the outcomes of the RRF (customer focus, operational effectiveness, public policy responsiveness, and financial performance)?**
- **Has the company controlled costs through optimization, prioritization and pacing?**
- **Has the plan appropriately integrated conservation, renewable generation connection, regional plans, smart grid, and any relevant public policies?**

Outcomes and Performance Metrics

The RRF is an outcomes-based approach. A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes. These outcomes are linked to performance metrics, which will be used to show whether the outcomes have been achieved. Utilities are expected to consider cost trends, benchmarking of comparable utilities, and learnings from their customer engagement in setting outcomes and performance metrics.

Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives. The outcomes should be based on the utility's business plan and should identify outcomes at the key program level that flow directly from the cost proposals. The outcomes should demonstrate the value proposition for customers and/or public policy goals. Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers and not a line by line review of expenditures. The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing.

Performance metrics are generally quantitative measures which will be used to assess whether the outcomes have been achieved; however qualitative measures may also be considered. Performance metrics ensure that the outcomes are measurable. For the pole line example noted above, the outcome could be increased reliability for that particular feeder.

The OEB has established a set of performance metrics for electricity distributors through its Performance Scorecard. In a rate application, the electricity distributor must identify metrics for its identified outcomes, which will often be in addition to those scorecard measures.

Other utilities (natural gas utilities, electricity transmitters and OPG) should establish performance metrics which are directly linked to the identified outcomes related to their business plans. These performance metrics will generally be part of the set of performance measures the utility has proposed for a performance scorecard (discussed further in the next section).

In reviewing a utility's proposed outcomes and performance metrics, the OEB's key considerations are:

- **A focus on strategy and results, not activities**
- **The need to demonstrate continuous improvement**
- **Outcomes which are demonstrated to be of value to customers**
- **Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement**

Performance Scorecards

Customers expect continuous improvement in the utility services delivered to them. Utilities must demonstrate their performance through effective and transparent reporting. As part of the RRF, the OEB has developed performance measures and standards for electricity distributors in four areas: customer focus, operational effectiveness, public policy responsiveness, and financial performance.[12] This Performance Scorecard brings greater transparency to utility performance and

[12] *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach*, March 5, 2014

enhances the ability to assess performance over time and to compare performance across utilities.

In its rate application, an electricity distributor should discuss its performance for each of the Performance Scorecard measures over the last five years, and explain the drivers for its performance. The OEB's review of a utility's proposals will consider the utility's past and target performance against the four RRF outcomes. The electricity distributor is also expected to discuss its plans for continuous improvement. It is expected to identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan.

All other utilities (natural gas utilities, electricity transmitters, and OPG) are expected to propose a scorecard (including the performance metrics linked to the proposed outcomes) to measure and monitor performance and, where appropriate, enable comparisons between utilities. The format should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. After the OEB has set approved scorecards for one or more electricity transmitters and natural gas utilities, those scorecards will provide additional guidance to other utilities filing applications. However, a utility is also encouraged to propose other performance categories and measures that it believes would be meaningful for its operations as an Ontario utility.

The proposed scorecard should include data for at least five years. A utility may propose measures for which five years of data is not yet available if it commits to collecting and reporting the data through the course of the plan. Furthermore, the lack of historical data should not be a barrier to the setting of new measures, especially if these are important to monitoring a utility's future performance e.g. a measure on system utilization could report on how a utility is managing its assets. The OEB may undertake further work to make enhancements to any scorecard proposed through an application as the OEB continues to develop its approach to performance assessment, and to maintain a level of consistency for scorecards between utilities.

In reviewing the proposed performance scorecard, the OEB's key considerations are:

- ***Whether the measures capture key factors of utility performance***
- ***Whether the scorecard enables assessments over time and appropriate comparisons with other utilities***
- ***Whether the utility has set reasonable targets for its performance metrics***

Benchmarking

Benchmarking will be used by the OEB to review a utility's proposals, including at the program level[13]. Utilities are expected to provide benchmarking analysis which supports their proposed plans and programs and demonstrates continuous improvement.

The OEB currently conducts total cost benchmarking for electricity distributors. An econometric model is used to generate efficiency rankings and assign electricity distributors to one of five groups based on their total cost performance, including both capital and OM&A costs. These results are used to set the productivity stretch factors for the incentive rate-setting mechanism (IRM) applications, and will also be a consideration in assessing a utility's cost trend performance. An electricity distributor is expected to provide a forecast of its efficiency assessment using the model for the test year. This provides the OEB with a directional indicator of efficiency.

Utilities are generally not required to present total cost benchmarking analysis as part of their applications, unless they have been ordered to do so through an OEB decision. Two other types of benchmarking are required in rate applications:

- External benchmarking to analyze specific measures or specific programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group
- Internal benchmarking to assess continuous improvement by the utility over time

Benchmarking need not be limited to unit cost benchmarking (e.g. the capital cost of a billing system per customer or the cost of cable or pipe per km). Performance benchmarking in areas such as reliability or other outcomes may also be appropriate. What is important is that the utility explains how it has interpreted the benchmarking and what actions it has taken as a result of it.

With the Custom IR rate setting options, a utility can customize the rate setting mechanism for their specific circumstances. Given this flexibility, the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term. When determining what areas to benchmark, a utility should consider the following potential criteria:

[13] Such as cost per pole replacement or billing costs per customer

- Key areas where the utility's performance is considered particularly strong or particularly weak
- Areas where expenditures are a key driver for the revenue requirement
- Areas that have been targeted for specific programs
- Areas where the OEB has expressed concern in past decisions
- Areas related to performance metrics and/or performance scorecard measures
- Linkages to customer engagement analysis

Utilities are expected to present objective, well researched benchmarking information, supported by a high quality and thorough analysis (using either third party or internal resources) that can be rigorously tested.

In reviewing benchmarking, the OEB will consider:

- **The structure of the benchmarking and the comparators used**
- **The quality of the benchmarking**
- **The linkages between the results of the benchmarking and the proposals in the rate application**

OM&A and Compensation Expenses

Under the RRF, the OEB has adopted an outcomes-based approach to regulation. As a result, the review of OM&A expenses will focus on the examination of outputs and programs, and whether there is evidence of continuous improvement, rather than the discrete line items or inputs to the OM&A budgets.

In addition, because employee compensation costs are already reflected in the proposed capital and operational programs, a detailed presentation of compensation is not necessary for the OEB's consideration of the proposed program costs to achieve the expected outcomes. The OEB does expect a utility to provide a description of its compensation strategies and policies (e.g. how salary scales are set and reviewed, how target salaries are compared to external benchmarks, performance pay structures, and the board of directors oversight process) and to clearly explain the reasons for all material changes to head count and compensation, and the outcomes expected from these changes. A utility should demonstrate clearly the linkages between its compensation strategies and policies and utility performance. Additional requirements for particular utilities may also arise from specific OEB directions in prior proceedings.

In reviewing a utility's proposed expenses for OM&A and Compensation, the OEB's key considerations are:

- **Have the costs been paced at the rate of inflation, and if not, what is the rationale for increased costs**
- **If the rationale for increased costs is customer or load growth, what is the relationship between increased costs and that growth**
- **A focus on strategy and results, not activities**
- **The need to demonstrate sustainable continuous improvement**
- **The outcomes that are expected from the proposed expenses**

Bill Impacts

The OEB is sensitive to customer concerns about energy bills. Customers are entitled to reliable service at reasonable rates. The OEB has adopted a number of policies to drive further efficiencies and to ensure utilities are focussed on providing value to customers. Customer needs and expectations, the pacing and prioritization of investment, and utility performance over time and in comparison to peers are all factors that the OEB considers, and are intended to drive effectiveness and continuous improvement. Utility proposals and plans ultimately translate into customer rates and bills. Rate changes and bill impacts are a particular focus of customers, and of the OEB. The OEB will hold utilities accountable to justify the bill impacts of their proposals; effective cost control will be expected.

Importantly, each utility can choose the rate-setting approach that best suits its particular needs. A utility is expected to tailor its proposals to meet the requirements of increased investment along with the requirements for enhanced productivity, cost control, and continuous improvement to create an appropriate rate profile.

In reviewing proposals in rate applications, the OEB will assess:

- **How the utility has considered total bill impacts in its planning**
- **How the utility has demonstrated the responsiveness of its expenditure plans to the need for stable and reasonable rates for customers**
- **Whether the pacing and prioritization of planned work is appropriate in light of the bill impacts of carrying out necessary investments**
- **What the bill impacts are for only those components of the bill that are within the control of the utility (no pass-through items)**
- **Whether any mitigation is warranted**

TAB 1(B)

Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

1 Introduction

The Ontario Energy Board regulates the rates of the 77 local electricity distributors that operate Ontario's local electricity delivery networks. These networks are essential to the seamless delivery of electricity from generators to end users. The cost of distributing electricity represents approximately 20% to 25% of the total electricity bill. Revenues collected from customers contribute to the ongoing operation and maintenance of the system as well as its expansion and modernization. Ontario's electricity distributors represent significant capital investments, with total assets of approximately $17 billion, and new investment of $1.9 billion in 2011. And while all distributors perform a similar service, their investment needs vary over time. Ontario's energy sector is evolving, as are the expectations of customers and the obligations placed on distributors as a result. The Board believes that our approach to regulation needs to evolve along with the sector.

The Board needs to regulate the industry in a way that serves present and future customers, and that better aligns the interests of customers and distributors while continuing to support the achievement of public policy objectives, and that places a greater focus on delivering value for money. A number of factors have prompted the Board's work on a renewed regulatory framework: government policy, aging infrastructure, customer concerns regarding rate increases, the increased maturity of the industry, and a need to harmonize and consolidate Board policies related to planning and rate setting.

The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board has developed a set of related policies to facilitate the achievement of these performance outcomes. The Board remains committed to continuous improvement within the electricity sector, The Board's policies for setting distributor rates as outlined below are supported by fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations.

The following are the three main policies:

- Rate-setting: There will be three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. Rate-setting is discussed in Chapter 2.

- Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. Planning is discussed in Chapter 3.

- Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. Performance measures and monitoring are discussed in Chapter 4.

In developing the policies in this Report, the Board has been guided by its objectives in relation to electricity, as listed in section 1(1) of the *Ontario Energy Board Act, 1998* (the "OEB Act"). These objectives are:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

4. To facilitate the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The first two objectives, the protection of consumer interests and the promotion of economic efficiency and cost effectiveness within a financially viable industry, are the foundation of the renewed regulatory framework. These objectives are reflected in the outcomes set out above and are the main principles of the distribution rate-setting and performance measurement policies. They are also key considerations in the emphasis on pacing and prioritization of capital investment embodied in the planning policy.

The remaining three objectives of the Board in relation to electricity are reflected in the policies regarding infrastructure planning. Steps toward achieving these public policy objectives in respect of conservation and demand management, smart grid implementation and the expansion or reinforcement of the system to facilitate renewable generation are incorporated into the planning policy.

With the exception of regional infrastructure planning and smart grid, which apply to both distributors and transmitters, the policies set out in this Report apply to distributors only at this time. In due course, the Board will provide further guidance regarding how the policies in this Report may be applied to transmitters.

Policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year. Specifically, the new instruments for all three rate setting methods will be available to those seeking to rebase rates effective May 1, 2014.

The Board is committed to monitoring and evaluating the effectiveness of its policies. It will do so by identifying desired policy outcomes and requiring annual monitoring and reporting to measure success against those outcomes. The Board will develop the policy evaluation framework for the renewed regulatory framework after further work has been completed in relation to the distributor performance “scorecard”. More information on this policy evaluation framework will be provided later.

4 Performance Measurement and Continuous Improvement

The renewed regulatory framework is a comprehensive performance-based approach to regulation that promotes the achievement of performance outcomes that will benefit existing and future customers. The framework will align customer and utility interests, continue to support the achievement of important public policy objectives, and place a greater focus on delivering value for money.

The achievement of the performance outcomes will be supported by specific measures and targets and annual reporting. Distributor performance will be compared year over year, both to prior performance and to the performance of other distributors. To facilitate performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes.

Under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers.

4.1 Monitoring Distributor Performance

Under the rate-setting approach described in Chapter 2, the Board will be setting rates under longer-term plans and allowing distributors to select the rate-setting method that best meets their needs and circumstances. Distributors will be required to undertake longer-term integrated planning that captures all categories of network planning, including those reflecting regional needs, as discussed in Chapter 3.

The Board has standards and measures for performance in place today;[19] however, the Board needs to assess whether these continue to be appropriate in light of the performance outcomes defined by the Board and the new rate setting methods. The Board also needs to consider the consequences that might flow from performance that does not meet the standards.

Benchmarking will become increasingly important, as comparison among distributors is one means of analyzing whether a given distributor is as efficient as possible.

Stakeholder Views

There was general stakeholder support for meaningful, empirically-based standards, performance measures and regulatory mechanisms, provided that the implementation costs do not outweigh the value for customers. Desirable characteristics that were identified included: focus on what customers value; promoting alignment of distributor and customer interests; and ability to accommodate differences within the distribution sector.

Stakeholder suggestions for objectives to underpin the development of distributor customer service and cost performance standards and measures included furthering market development; revealing infrastructure investment planning effectiveness or cost performance; facilitating price transparency for customers; and improving existing customer service standards.

A number of stakeholders acknowledged the cost performance incentives that are inherent in incentive regulation. Caution was expressed about implementing direct financial incentives until Board-approved measures are in place. Stakeholders were divided on process incentives; some were supportive of streamlined regulatory processes for high-performing distributors while others were opposed to limits being

[19] These are identified in the *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors.*

placed on the review of applications based on the quality of evidence or the applicant's past performance.

The Board's Conclusions

Performance Outcomes and the Electricity Distributor Scorecard

The Board is establishing performance outcomes that it expects distributors to achieve in four distinct areas:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board concludes that a scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. The scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons, which are critical to the Board's rate-setting approach under the renewed regulatory framework. Distributors will be required to report their progress against the scorecard on an annual basis.

A sample of a possible scorecard based on a simple sub-set of the Board's current standards and measures (such as the service quality requirements in the *Distribution System Code*) is provided below. The sample is provided for illustrative purposes only, as the Board has not yet determined content of the scorecard to be used. The Board expects that the scorecard will evolve as appropriate standards and measures are developed to assess distributor performance against the identified outcomes.

Figure 3: Sample Scorecard

Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance
services provided in a manner that responds to identified customer preferences	*continuous improvement in productivity and cost performance; and delivery on system reliability and quality objectives*	*delivery on obligations mandated by government (specific legislation or via directives to the Board)*	*financial viability maintained; and savings from operational effectiveness are sustainable*
• Customer complaints • Connection statistics • Connection of New Service • Reconnection • Telephone Accessibility • Appointments Met • Written Response to Enquiries • Emergency Response • Telephone Call Abandon Rate • Appointments Scheduling • Rescheduling a Missed Appointment	• Distribution Losses • System Average Interruption Frequency Index (SAIFI) • System Average Interruption Duration Index (SAIDI) • Customer Average Interruption Duration Index (CAIDI) • Momentary Average Interruption Frequency Index (MAIFI)	• Electricity Conservation (Kwh) • Peak Demand Reductions (kW)	• Current Ratio • Debt Service Capability • Interest Coverage • OM&A Cost per Customer • Return on Equity

Standards and Measures

The Board will engage stakeholders in further consultation on the standards and measures to be included in the distributor scorecard. The standards and measures must be suitable for use by the Board in monitoring and assessing distributor performance against expected performance outcomes, in monitoring and assessing distributor progress towards the goals and objectives in the distributor's network investment plan, in comparing distributor performance across the sector and identifying trends, and in supporting rate-setting.

The Board has established a set of objectives to guide the consultation. Standards and measures should:

- be aligned with, and reflect a distributor's effectiveness in achieving, the performance outcomes listed in Chapter 1;
- be reflective of customer needs and expectations;
- encourage year-over-year performance gains;
- reveal current performance and signal future performance;
- reflect a distributor's effectiveness in prioritizing and pacing investment (with regard to total bill impacts) and implementing its capital plan;
- be measureable by each distributor, and be aligned with their reporting for their own internal purposes to the extent possible;
- consider the characteristics of a distributor's service territory; and
- be practical.

4.2 The Role of Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking. Expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework policies.

Stakeholder Views

There was general support for the continued development and use of benchmarking tools, with further empirical work on the distribution sector identified as a priority. It was noted that the cost of this exercise should not exceed its value, recognizing that there may be limits to the practical use of cost comparison and benchmarking information. Among suggestions offered for the further use and development of benchmarking tools were the use of external data, benchmarks and productivity trends to establish boundaries within which distributors should operate; the more rigorous implementation of benchmarking in rate proceedings; and the adoption of a "balanced scorecard" approach to benchmarking to reflect customer and distributor diversity.

The Board's Conclusions

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4th Generation IR and the Annual IR Index, and will inform the Board's review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor's rates are set, the distributor will continue to be included in the Board's benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.

4.3 Regulatory Mechanisms

The Board is committed to ensuring optimal performance and value for customers, and will continue to enhance its regulatory mechanisms where necessary to achieve this goal.   In initiating the performance-based approach, the Board will maintain its existing regulatory mechanisms, subject to certain refinements. Specifically, the X-factor will be refined as discussed in Chapter 2 and the "publication of distributor results" mechanisms referred to above (among possible others) will be integrated into the electricity distributor scorecard.

The Board's incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board's current policies as set out in the *Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors*, the Board expects that new approaches may be required.

In addition, appropriate consequences should flow from unsatisfactory performance against the Board's standards, in order to maintain the integrity of the Board's outcome-based approach and its approach to rate-setting.

Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- The establishment of an "efficiency carry-over" mechanism;
- Development of incentives to;
  - reward superior performance;
  - encourage innovation;
  - encourage asset optimization; and
- Potential consequences for inferior performance.

The development of these regulatory mechanisms will be aligned with the standards and measures referred to above.

4.4 Implementation

To establish the outcome based framework and provide for effective monitoring of distributor performance, the Board will:

- define the standards and measures that will be applicable to distributors;
- establish benchmarking models (through further empirical work);
- establish the reporting requirements applicable to distributors, including the format of the performance scorecard; and
- determine the regulatory mechanisms that will be used in conjunction with those standards and measures (in due course).

A stakeholder working group will be established to provide staff with expert assistance and to help staff review and evaluate proposals regarding performance standards, measures, and the development of benchmarking. This will also include consideration of rate adjustment indices (i.e., inflation and X factors). Staff and consultant reports will be issued for comment.

With respect to benchmarking, the objective is to establish total cost benchmarking for the 2014 rate year. Further work will involve comprehensive benchmarking (i.e., model(s) that combine standards for utility customer service and cost performance) to be applied in subsequent rate years.

The end result of this work will be a Supplemental Report of the Board expected to be issued in mid-2013. Regulatory instruments such as the Reporting and Record Keeping Requirements will be amended as necessary to implement the Supplemental Report.

Work carried out in this consultation to develop total cost benchmarking will provide the foundation for the development of the Board's approach to comprehensive benchmarking. The overall approach and timeline for such additional work will be issued after the substantial completion of work planned for implementation for the 2014 rate year.

	Product	Expected issuance	Process
Standards and measures	Supplemental Report of the Board, including distributor scorecard	June 2013	Staff proposal Stakeholder meeting Working group meetings Board staff report to the Board (for comment) Stakeholder meeting Written comments
	Amendments to RRR if needed	July 2013	Notice and comment
Benchmarking	Supplemental Report of the Board (same document as above), plus consultant report on approach to total cost benchmarking	June 2013	Validation of data by distributors Consultant Concept paper Stakeholder meeting Working group meetings Consultant report (for comment) Stakeholder meeting Written comments

4.4.1 Issues to be addressed in relation to standards, measures and regulatory mechanisms

Working with stakeholders, the Board will consider the following areas in the context of developing a scorecard and performance standards, and measures to facilitate annual monitoring of distributor performance.

Assessing performance outcomes:

- confirm the standards and measures that best reflect a utility's effectiveness and/or continuous improvement in achieving the performance outcomes.

Effective planning & implementation:

- establish measures that best reflect a distributor's effectiveness with respect to:
    - planning - prioritizing and pacing investment with regard to total bill increases to consumers;
    - plan implementation – progress in achieving targets against the capital plan; and
    - plan achievement – achievement of the goal(s)/outcome(s) originally committed to in an approved capital plan

Regulatory reporting:

- establish the electricity distributor scorecard to effectively organize how utilities report on their performance to the Board.

Regulatory Mechanisms:

In due course, the Board will further engage stakeholders to consider the appropriate form and implementation of:

- an "efficiency carry-over" mechanism; and
- performance incentives to reward achievement of utility plan objectives, and/or encourage and reward implementation of truly innovative technologies to address system and customer requirements.

4.4.2 Issues to be addressed in relation to benchmarking

The use of OM&A data to benchmark distributors for stretch factor assignment purposes in the 3rd Generation IR plan is the foundation for a more comprehensive (e.g., total cost) benchmarking approach. Work to develop the more comprehensive benchmarking model(s) will also create the dataset necessary to estimate Ontario TFP trends.

The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the utility customer service and cost performance outcomes, including total cost benchmarking and an Ontario TFP study. This work will inform the Board determination on inflation and X factors for rate-setting.

The Board will also determine how to make expanded use of benchmarking for assessing distributor performance as well as to inform rate setting. In particular, the Board will establish how its standards for utility service and cost performance and various empirical tools and benchmarking will further inform (a) utility planning processes, (b) utility applications to the Board, and (c) the Board's review processes.

TAB 2(A)

2003 CarswellNfld 389
Newfoundland and Labrador Board of Commissioners of Public Utilities

Newfoundland and Labrador Hydro, Re

2003 CarswellNfld 389

IN THE MATTER OF the Electrical Power Control Act, SN 1994 c. E-5.1 (the "EPCA") and the Public Utilities Act, RSN 1990 c. P-47 (the "Act") and their subordinate regulations

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) for approval of: (1) its 2004 Capital Budget pursuant to s.41 (1) of the Act; (2) its 2004 capital purchases and construction projects in excess of $50,000 pursuant to s.41 (3)(a) of the Act; and (3) its estimated contributions in aid of construction for 2004 pursuant to s. 41 (5) of the Act

G. Fred Saunders Presiding Chair, Gerard Martin Commr., Donald R. Powell Commr.

Judgment: September 5, 2003
Docket: P.U. 29 (2003)

Counsel: Counsel — not Provided

Subject: Public

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Public law --- Public utilities — Regulatory boards — Practice and procedure — Miscellaneous

Decision of the Board:

BACKGROUND

1 On March 28, 2003 the Board of Commissioners of Public Utilities (the "Board") received an application from Hydro requesting an order of the Board pursuant to Section 41 of the *Act* approving:

(1) its 2004 Capital Budget in the amount of $34,465,000;

(2) its 2004 capital purchases and construction projects in excess of $50,000; and

(3) its proposed estimates of contributions in aid of construction of approximately $240,000.

2 The Board decided that the application would be the subject of a public hearing and caused notice of the public hearing to be published in several newspapers circulating throughout the Province commencing on April 23, 2003.

3 Notices of Intervention were received from:

Newfoundland Power Inc.,

Corner Brook Pulp and Paper Company Ltd., Abitibi Consolidated Company of Canada, Stephenville and Grand Falls Divisions, and North Atlantic Refining Limited (the "Industrial Customers").

64 The Industrial Customers did not make a submission on this project.

65 *The Board accepts Hydro's justification for the project and will approve this project to proceed as Hydro proposed.*

Replace Insulators on line TL233 (230kv Buchans to Bottom Brook - $1,054,600 (B-27)

Replace Insulators, Bottom Waters line 1, Fleur de Lys line 1 and South Brook line 1 - $944,500 (B-45)

66 Both projects propose the replacement of insulators manufactured by Canadian Ohio Brass and installed approximately 30 years ago. These insulators are part of a group of insulators that have caused failures industry wide due to cement growth radial cracks that result in moisture intrusion causing line failures to occur. The problem was recognized in the 80's and a gradual replacement program has been carried out since that time to remedy the problem. The Board has approved the total replacement concept for both Hydro and Newfoundland Power Inc. in orders emanating from previous capital budget applications. Hydro states in its application that during the period 1996 to 2003 the lines have averaged two to four outages each year due to defective insulators.

67 Mr. Martin testified that the program falls into the category of preventative maintenance in the interest of reliability improvement and while an immediate problem does not appear to exist it will become one over time since the failure statistics are increasing (Transcript, July 11, pp 71 and 72).

68 The Industrial Customers argued that replacement program scheduled for 2004 could be delayed without seriously jeopardizing Hydro's reliability standard.

69 *The Board believes that the project conforms with Hydro's overall plan to totally replace the defective insulators over time providing funds are available and are not limited by other priorities, therefore, approval will be granted to proceed as proposed.*

Upgrade 138kv and 66kv Protection - $150,200 (B-29)

70 This project consists of the purchase and installation of microprocessor based relays to improve protection of designated 138kv lines at Deer Lake and Sunnyside Terminal Station and 66kv lines at Deer Lake Terminal Station.

71 Hydro submitted in evidence that the existing 30 year old electro mechanical relays will be removed as they are difficult to maintain and calibrate and have an adverse effect on system performance. The replacement relays can be remotely interrogated allowing timely analysis of problems on the lines or with the relays themselves. Mr. Martin testified that this project is part of an extensive ongoing program conducted over the past several years by Hydro in an effort to upgrade its protection and control capabilities on the bulk transmission system (Transcript, July 11, pp 75 - 77). He also testified, in cross examination by the Industrial Customers, that Hydro has experienced ten inadvertent trips of these relays in the last nine years but there is no indication that the situation is deteriorating (Transcript, July 11, p. 76 and 77).

72 The Industrial Customers argued that the relays sought to be replaced are functional and no compelling reason has been given to justify immediate replacement and that the project can be deferred.

73 *Although Hydro did not consider the impact on maintenance cost or reliability of the system if this project were to be deferred, the Board will approve it since the anticipated improvement to the control capabilities on the bulk transmission system is an essential upgrade to improve system protection capabilities.*

General Properties Projects

Replace Energy Management System at the Energy Control Centre - $4,292,700 (B-53)

74 This project is for the replacement of the existing Energy Management System (EMS) computer software and hardware infrastructure with state of the art hardware and software which provides greater flexibility for future

TAB 2(B)

IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION
Transmission System Capital Plan
F2006 to F2015 Application

DECISION

September 23, 2005

BEFORE:

Robert H. Hobbs, Chair

1.0 INTRODUCTION

1.1 Application

On March 23, 2005 the British Columbia Transmission Corporation ("BCTC") filed its F2006 to F2015 Transmission System Capital Plan ("the F2006 TSCP") with the Commission. The Application was filed under Sections 45(6) and 45(6.1) of the Utilities Commission Act. This application is the second Transmission System Capital Plan. The first was filed in May 2004 and subsequently approved by Order G-103-04. The first plan requested approval for capital expenditures beginning in F2005. This plan describes projects within the period F2006 to F2015; however, BCTC only requests approval for capital expenditures beginning in F2006 and F2007. BCTC will continue to file annual capital plans and, in the next plan, BCTC will request approval for any new projects identified for F2007 and for F2008.

1.2 Regulatory Requirements

BCTC is required by Section 45 of the Utilities Commission Act to file annual capital plans. Under a Master Agreement between BCTC and British Columbia Hydro and Power Authority ("BC Hydro"), BCTC is responsible for planning, constructing and obtaining regulatory approvals for enhancements, reinforcements, and sustaining and growth investments to BC Hydro's transmission system. BCTC has therefore filed for approval of capital investments for BC Hydro's transmission system as well as for capital investments directly funded and owned by BCTC.

1.3 Orders Sought

In its Application BCTC seeks:

- An Order that its capital plan meets the requirements of Sections 45(6) and 45(6.1) of the Act;
- An Order approving this capital plan under Subsection 45(6.2)(a) of the Act; and
- Certain Orders under Subsection 45(6.2)(b) of the Act as set out in Section 7 of the BCTC Transmission System Capital Plan (F2006-F2015).

The order(s) sought with respect to Subsection 45(6.2)(b) of the Act pertain to the projects listed in the Growth and Sustaining Capital Portfolios for the BC Hydro transmission system and for the BCTC Capital Portfolio for business support systems, control centre technologies, facilities management, and information technology.

<u>Commission Findings</u>

The Commission Panel notes a large increase in the Overhead Life Extension Program, especially beyond F2006/F2007, compared to expenditures in the past five years (BCUC IR 1.59.4). The previous two years' expenditures of $6,600,000 in F2004 and $10,500,000 in F2005 include costs of $12,400,000 for COB related projects, which would have left approximately $2,350,000 per year for other Overhead Life Extension activities. The justification of ramping up this expenditure to an average of $7,575,000 per year in F2006/F2007 and over $12,500,000 after that has not been supplied, and lower expenditures may be prudent until investment increases can be justified by decreasing trends in either overall asset base health or reliability indices. There are several new programs, such as the Overhead Line Seismic Withstand Program and the Overhead Lines Wind and Ice Withstand Program that, although not large compared to the overall budget, contribute to the overall large increase of the Sustaining Capital Portfolio over previous years. The negative consequences associated with low-probability natural physical events may be better absorbed within the inherent N-1 design capability of the system, rather than intensively upgrading all components to present-day standards.

The Commission Panel also notes a sizeable increase in right-of-way-related expenditures and a significant cost and low priority associated with the Deficient Rights Study and Acquisition Program (Exhibit B-1, p. 137). Again, with the upward pressure on the overall Sustaining Capital Portfolio from higher-priority programs, the overall schedule of this program should be reviewed to help level out long-term effects.

The remainder of the proposed F2006 and F2007 expenditures in the overhead lines and rights of way asset classes amounts to $17,706,000. The COB Clamp-top Insulator Replacements and COB Suspension Insulator Replacements Programs account for $11,000,000 of this remainder. The Commission Panel notes that the completion estimate for these Programs will be $9,000,000, or almost 60 percent over their initially approved budgets (BCUC IR 2.113.1). There is a balance to be struck between risk and cost that should be reviewed for these programs.

Based on the foregoing discussion, the Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $3,500,000 and $4,500,000, respectively, in the Overhead Lines and Rights of Way Sustaining Capital Programs.

TAB 3

RP-2003-0063
EB-2003-0087
EB-2003-0097

IN THE MATTER OF.the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

1. THE APPLICATION AND THE PROCEEDING

1.1 THE APPLICATION AND BACKGROUND

Union Gas Limited ("Union" or the "Applicant" or the "Company" or the "Utility") filed an application dated May 2, 2003 (the "Application"), with the Ontario Energy Board (the "Board") pursuant to section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "Act"), for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas, effective for the year commencing January 1, 2004. The Board assigned file number RP-2003-0063 to the Application. The Board issued a Notice of Application dated May 22, 2003, with a letter containing directions for service.

Union filed a cost of service ("COS") application which will be used to establish rates for fiscal 2004 and would also serve as the base for Union's rate applications for subsequent years, if it files a Performance Based Regulation ("PBR") methodology for its 2005 rates. In the RP-1999-0017 Decision, the Board had approved a three-year trial PBR plan for years commencing January 1, 2001, 2002, and 2003.

1.2 THE PROCEEDING

Union filed evidence in support of the proposed 2004 revenue requirement, described as Phase I evidence, on May 23, 2003. Union undertook to file evidence in support of its 2004 cost allocation and rate design proposals, described as Phase II evidence, on or before June 20, 2003. The Board assigned file numbers RP-2003-0063\EB-2003-0087 and RP-2003-0063\EB-2003-0097 respectively to the two phases of the Application.

pension costs. Therefore, Union argued that its accounting treatment was not only appropriate, but required, since contributions to a plan in a surplus position are effectively prohibited.

Board Findings

The Board notes that Union is requesting increases in all areas of Human Resources costs for 2004. The Board will deal with each of these individual elements of the request.

Salaries and Wages

Union's salaries and wages are shown in Exhibit N6.11 to have increased by 17.2% when comparing the 2004 forecast costs to the EBRO 499 level on the basis of average salary per FTE. The Board notes that the level of increases averages 2.5% for all years except 2003 over 2002, for which it is 6.4%. The Board shares the concerns of a number of intervenors regarding the anomalous nature of this 6.4% increase, compared to the increases in the other years. Such a sharp increase in this area of management should be supported by specific evidence providing a rationale for the magnitude of the divergence from previous years. The Board concludes that Union has failed to provide a sufficient evidentiary basis for the totality of the claim. Accordingly, the Board is in agreement with the proposal of CAC that Union be allowed an average annual increase in these costs of 2.5% annually for the 2004 test year versus the EBRO 499 level of cost recovery. The Board will therefore allow a 2004 recovery of $143.7 million, representing a reduction of $5.2 million from the level proposed by Union.

Incentives

The Board is in agreement with Union's use of incentive payments as a legitimate element of a total compensation package offered to attract and retain qualified managers and staff in a competitive market for human resources. The question which the Board must consider is the extent to which ratepayers benefit from, and should bear the cost of such payments.

The Board finds that the use of incentive payments is a reasonable element of Union's employee compensation and benefits ratepayers over the longer term by allowing Union to compete for high quality human resources, leading to a more efficient operation of the Utility.

To the extent possible, the operations of the Utility should be consistent with good management in other sectors of the business community. As indicated elsewhere in this Decision, the Utility should be in a position to manage its business confidently and conventionally. Incentive programs are a common element of business management in all sectors of the economy, and have come to be regarded by employees, and prospective employees, as an essential element of compensation. Unless the incentive
programs can be shown to be extravagant or otherwise objectionable, they should be supported as part of the revenue requirement. It would be perilous to create a situation in which the gas distribution utility, alone among business categories, could not effectively attract and keep quality employees through the offering of reasonable incentive programs.

The Board therefore approves the request for the incentive component of total compensation and makes no additional adjustments to salaries and wages as a result of its consideration of this item.

<u>Benefits</u>

Where benefit costs are concerned, the Board accepts the evidence presented by Union, supported by Towers Perrin, that benefit costs per FTE have risen by approximately 28% since 1999, due mainly to health cost increases. This evidence was not credibly challenged. The Board also notes that the total number of FTE's over the same period has declined by approximately 400. Accordingly, the Board finds that the net impact of the above variables results in an increase of $2.2 million in benefit cost over this period and accepts that the projected 2004 benefit cost of $25.5 million is reasonable.

Post Retirement Benefits

The Board also accepts the evidence presented by Union, supported by Towers Perrin, that the cost of post retirement benefits has increased in the period from EBRO 499 to 2004, due mainly to changes in accounting rules and discount rate assumptions. Therefore, the Board finds the request of $5.4 million in the 2004 revenue requirement to be reasonable under present circumstances.

Pensions

Where Pension costs are concerned, the Board accepts that these costs have increased for the company as a result of negative returns on pension fund assets due to a decline in equity markets and also due to increased pension obligations as a result of a declining trend in long term bond yields.

The Board notes the concerns of intervenors regarding the negative returns on pension fund assets, but also notes that the Board has been provided with no evidence to support the position that the achieved level of performance was due to imprudent actions by the Company. The Board also finds that increased obligations due to a declining trend in long term bond yields are beyond the immediate control of the Company. The Board therefore approves the pension cost component of the employee compensation package.

TAB 4

Energy Utility Rate Setting

A PRACTICAL GUIDE TO THE RETAIL RATE-SETTING PROCESS FOR REGULATED ELECTRIC AND NATURAL GAS UTILITIES

Lowell E. Alt Jr.

management systems in simulations to determine distribution equipment peak data that in turn is used to find the best cost-causative allocation factors.

Rate of Return Analysis

Rate of return analysis is done at the end of the cost of service study and is based on the equal rates of return principle discussed in the next section. First, the earned rate of return on rate base is calculated for each rate schedule so that it may be compared with the target system average rate of return. The target system average rate of return is the commission-determined allowed rate of return on rate base for the utility as a whole. The earned rate of return is calculated by subtracting the allocated expenses for a rate schedule from its test period revenues to get net income or return which is then divided by the rate schedule's allocated rate base. Under the aforementioned principle, a rate schedule that has an earned rate of return on rate base of less than the target system average is not covering its costs and needs a rate increase.

Cost of Service Principles

Three principles used in cost of service are cost causation, equal rates of return and gradualism.

Cost Causation

Cost causation is the principle that cost should be borne by those who cause them to be incurred. This is done not just because it is perceived to be fair, but to send a correct price signal to the consumer. Use of correct price-signals aids in achieving economic efficiency. Economic efficiency means an efficient allocation of society's resources. The cost causation principle is implemented by classifying costs based on cost-defining service characteristics and using cost-causative allocation methods and factors. An example of cost-causative classification is the classifying of fuel cost as energy since the utility's energy costs are related to the energy consumption of customers. An example of a cost-causative allocation method is the allocation of fuel cost among users on the basis of each user's relative share of total kilowatt-hours because fuel cost is a variable cost primarily caused by the total kilowatt-hours produced.

Equal Rates of Return

Equal rates of return are a traditional measure of a fair sharing of total costs among rate classes or schedules. The total cost of utility service, which is usually referred to as the revenue requirement, is composed of total expenses plus a return on rate base. The total cost to serve each rate class is the sum of the operating expenses allocated to the rate class plus the target system average rate of return on the rate base allocated to that rate class. For each rate class to pay its fair share of the total cost-of-service, it must pay the same system rate of return. Only when the rates of return are equal is there a fair apportionment of the total cost-of-service. By comparing the actual earned rate of return on rate base for each class to the system average rate of return, you can determine if that rate class has contributed more or less than the average to the Company's total rate of return on rate base. If the earned rate of return for a rate class is less than the average, then that rate class is not paying its fair share of the total cost of service. Only when the earned rate of return on rate base is equal for all rate classes can you be sure that the total cost of service has been fairly apportioned among the rate classes.

Gradualism

Gradualism is a principle used in implementing cost of service study results. Cost of service is a moving target because of shifts in cost allocations over time due to changing service characteristics such as kilowatt-hour usage and peak demands as well as cost study refinements, corrections and method changes. Gradual movement to cost of service prevents flip-flopping of rates due to changes over time and maintains stability of rates by

TAB 5

2004 ABCA 215
Alberta Court of Appeal

Atco Electric Ltd. v. Alberta (Energy & Utilities Board)

2004 CarswellAlta 949, 2004 ABCA 215, [2004] 11 W.W.R. 220, [2004] A.W.L.D. 501, [2004] A.J. No. 823, 132 A.C.W.S. (3d) 803, 18 Admin. L.R. (4th) 243, 31 Alta. L.R. (4th) 16, 339 W.A.C. 1, 361 A.R. 1

ATCO Electric Limited, Appellant and Alberta Energy and Utilities Board, Respondent

Fraser C.J.A., McFadyen, Picard JJ.A.

Heard: January 15, 2004
Judgment: July 13, 2004
Docket: Calgary Appeal CA01-00476, 0201-0013-AC, 0201-0023-AC

Counsel: H.M. Kay, Q.C., L.G. Keough for Appellant
J.R. McKee, A.E. Domes for Respondent

Subject: Public

Headnote

Public utilities --- Operation of utility — Rates — General

Utility A Ltd. entered into negotiated settlements establishing rates payable to it for electricity services provided for years 1999/2000 and 2001/2002 — Under legislation governing electrical utilities, no negotiated settlement was effective unless it was approved by Alberta Energy and Utilities Board — In determining whether to approve negotiated settlement, board must be satisfied that it was not contrary to public interest — In approving settlements, board ruled that A Ltd. was not entitled to recover 2000 carrying costs on deferral accounts and was not entitled to full amount of 2001 carrying costs and 2002 carrying costs sought by A Ltd. on deferral accounts — A Ltd. appealed — Appeal dismissed — Board did not err in methodology it used to assess appropriate capital structure for costs of financing A Ltd.'s deferral accounts — Board has jurisdiction to approve negotiated settlement even though it did not provide utility with fair and reasonable compensation for all its costs — When board is presented with "package deal" negotiated settlement agreed to by utility, board is under no obligation to consider utility's economic interests in assessing whether negotiated settlement is in public interest.

APPEAL by electrical power utility from decision of Alberta Energy and Utilities Board with respect to negotiated settlements for utility rates.

***Fraser C.J.A.*:**

I. Introduction

1 In 1995, the Alberta government decided to deregulate, or more precisely, restructure certain aspects of the electrical industry in this province.[1] As a result, it passed new legislation paving the way for deregulation: *Electric Utilities Act*, S.A. 1995, c. E-5.5 (the *1995 Act*). The restructuring model selected in aid of this objective was subsequently refined through legislative amendments made in 1998 and 2003: *Electric Utilities Amendment Act*, S.A. 1998, c. 13; and *Electric Utilities Act*, S.A. 2003, c. E-5.1. For purposes of this appeal, the 1998 version of the Act is the most relevant and I refer to it as the *1998 Act* and the 2003 version as the *EU Act*. To shift from regulated public utilities exercising significant market

168 What then were the Board's obligations under the *Deferral Accounts Regulation*? Section 4(1) conferred on the Board the authority to determine the costs of financing certain deferral accounts of a utility:

> The Board must determine an amount that is payable in 2001 to the owner of an electric distribution system in respect of the cost of financing the amounts in the owner's deferral accounts in 2001.

169 Section 4(2) of the *Deferral Accounts Regulation* defined in turn the kinds of costs to be recovered by the utility:

> In determining an amount under subsection (1), the Board must ensure that an owner is able to recover the prudent cost of financing the amounts in its deferral accounts which may include debt financing, equity financing or a combination of debt and equity financing.

170 In the result, therefore, given the dual statutory source of the Board's authority coupled with the contractual authority, the Board had the jurisdiction to determine ATCO's carrying costs for the Deferral Accounts, both PPDAs and NPPDAs, in accordance with the "prudent costs" standard. It should be noted that the Board's use of a WACC approach for purposes of calculating those carrying costs — under which the overall rate of return would be calculated as a weighted average of the rates of return on the various components — is not in issue. Nor is there any disagreement about ATCO's entitlement to carrying costs for 2001 and the first quarter of 2002 on the Deferral Accounts. What is in dispute is the level of those carrying costs and in particular the basis on which the Board established the WACC for calculation of those costs.

C. Board's Reasons

171 The Board used the stand-alone principle as a critical element in its assessment of carrying costs on the deferral accounts of a number of utilities before it in Decision 2001-92, one of which was ATCO. The purpose of the stand-alone principle is to notionally isolate and categorize — for accounting and rate-making purposes — the costs incurred in the operation of a discrete business function of a utility. The Board distinguished between two recognized applications of the stand-alone principle. First, the principle could be used to allocate costs as between regulated and non-regulated activities of an integrated utility, the theory being that customers should pay only for the costs of the utility's providing the regulated service, not the costs of other non-regulated activities. Hence the need to isolate the utility's costs associated only with the regulated service. However, the Board concluded that this application of the stand-alone principle, frequently relied on in utility regulation, was not relevant to the task before the Board.

172 What was relevant in the Board's view though was the second accepted application of the stand-alone principle. This application involves allocating costs incurred by an integrated utility amongst its various business functions — for instance, the costs incurred in administering deferral accounts — so that just and reasonable rates might be set for each business function. In using this principle to determine a utility's costs of financing the administration of deferral accounts, the Board essentially had three options open to it.

173 The first, which some distribution utilities who were parties to Decision 2001-92 urged on the Board, was to determine a WACC for a stand-alone deferral accounts operation that would be required to seek financing in the marketplace on the basis of that business alone. The second was to treat the deferral accounts operation as a stand-alone business unit but one that was part of a distribution utility's business operations. The third, and the one selected by the Board, was to treat the deferral accounts operation as a stand-alone business unit but one that was part of an integrated utility's business operations. At the hearing before the Board, it appears that ATCO argued in support of the first option. ATCO now disagrees with all three, arguing that reliance on the stand-alone principle is misplaced since there was no separate deferral accounts business.

174 ATCO also challenges the Board's conclusions that the deferral account business function was low risk and that only a 15% equity component was therefore warranted. ATCO insists that the applicable WACC should be based on the standard WACC for the overall ATCO corporate entity because the administration of the deferral accounts was not a

174 ATCO also challenges the Board's conclusions that the deferral account business function was low risk and that only a 15% equity component was therefore warranted. ATCO insists that the applicable WACC should be based on the standard WACC for the overall ATCO corporate entity because the administration of the deferral accounts was not a separate business service. With respect to the risk the Board assigned to the "deferral account business", ATCO argues that since the Board was empowered to review ATCO's Deferral Accounts, and other parties were seeking to disallow certain amounts, ATCO was exposed to more risk than that assigned by the Board. In ATCO's view, there was a very real potential for disallowances.

1. Board's Reliance on Stand-Alone Principle

175 I do not find ATCO's arguments on this issue persuasive. ATCO's primary challenge is to the Board's basing its determination of a WACC on what it characterizes as a "fictional" deferral accounts business. It is true that the administration of the deferral accounts was not operated as a separate stand-alone business by any of the utilities. But that is not the point. The issue facing the Board was how to evaluate the risks associated with the administration of these deferral accounts for the purposes of calculating "prudent" financing costs thereon. Thus, the focus of the Board's analysis was on risk, both business and financial, of this particular business function. The key point — and the one which ATCO appears to ignore — is the Board's conclusion that the risks associated with the administration of deferral accounts were far less than the risks associated with the other business functions of an integrated utility. Hence, in determining the appropriate WACC to apply to the operation of the deferral accounts, the Board concluded that it would not be proper to calculate those costs as if the deferral accounts were in the same category of risk as the other business functions of an integrated utility when they were not.

176 That is the reason the Board chose to treat the administration of the deferral accounts as a separate stand-alone business unit within the totality of an integrated electric utility and to calculate the costs of financing on this basis. I see no error by the Board in its application of the stand-alone principle. The Board explained at length its rationale for, and method of, applying the "stand-alone" principle to the administration of deferral accounts: Decision 2001-92 at pp.24-29, AB Vol. II, F105-F110. In particular, it pointed out that under restructuring, it was necessary to determine business risk and return by function so that the Board might fix rates and tariffs by business function: Decision 2001-92 at p.26, AB Vol. II, F107. This approach is entirely reasonable.

177 The Board also emphasized that treating the administration of deferral accounts on a "stand-alone" basis but within the context of an integrated utility was wholly consistent with the Board's approach in Decision U99099 for three other business functions of an integrated utility: generation, transmission and distribution services. The fact that the deferral accounts were treated in a similar fashion to other business functions of an integrated utility represents a significant factor supporting the reasonableness of the Board's approach.

178 I also note that the evidence of the Independent Financial Experts to the Board, Messrs. Demcoe and McCormick (collectively the "IFE"), supports the Board's approach. The IFE testified that the stand-alone principle was developed as a shield to protect customers from higher rates due to subsidization of non-regulated activities. Therefore, in the IFE's view, it ought not to be used as a sword to require customers to pay higher rates simply because of a notional separation of what remained as integrated business functions. The IFE also argued that the stand-alone principle did not reflect the reality of how a utility accessed the capital market. When a utility sought financing, this was not done on behalf of some discrete business function in the organization but rather on behalf of the larger corporate entity itself. For these reasons, the IFE concluded that:

> ... the Board should Anot apply the stand-alone principle by rote. Instead the Board should deal with the reality, utilize independence of thought, question assumptions and think through whether an approach that has been applied in the past in different circumstances should be applied now in new circumstances. Such an approach should lead the Board to deal with reality and to decline to apply the stand-alone principle to the detriment of the customers of the [distribution companies]. [67]

Deferral Accounts. Finally, from a practical perspective, the Board is entitled to even more deference when dealing with known facts since a utility's ability to assert that the Board has relied on improbable or unfair assumptions in assessing future costs and recovery periods is correspondingly diminished.

D. Summary

190 For these reasons, having regard to the standard of review, the Board did not err in the methodology it used to assess an appropriate capital structure for the costs of financing ATCO's Deferral Accounts. Not only are the Board's reasons not patently unreasonable, in my view, they are entirely reasonable.

IX. Conclusion

191 The answers to the three questions posed above are as follows:

> Question 1: Did the Board err in finding that ATCO was not entitled to 2000 Carrying Costs on the Deferral Accounts?
>
> Answer: No.
>
> Question 2: Did the Board err in approving the Negotiated Settlements or alternatively, in failing to vary the Negotiated Settlements?
>
> Answer: No.
>
> Question 3: Did the Board err in the methodology it used to calculate ATCO's 2001 Carrying Costs and 2002 Carrying Costs on the Deferral Accounts?
>
> Answer: No.

192 The appeal is dismissed. In accordance with s.26(10)(c) of the *AEUB Act*, I hereby confirm the Decisions of the Board.

***McFadyen J.A.*:**

I concur.

***Picard J.A.*:**

I concur.

Appeal dismissed.

Appendix A — Definitions

1995 Act	*Electric Utilities Act*, S.A. 1995, c. E-5.5.
1998 Act	*1995 Act* as amended by the *Electric Utilities Amendment Act*, S.A. 1998, c. 13.
2000 Carrying Costs	carrying costs for 2000 on the 2000 distribution pool price and non-pool price deferral accounts under the 1999/2000 Settlement.
2001 Carrying Costs	carrying costs for 2001 on the 2000 distribution pool price and non-pool price deferral accounts under the 1999/2000 Settlement.
2002 Carrying Costs	carrying costs for 2002 on the 2000 distribution pool price and non-pool price deferral accounts under the 1999/2000 Settlement.
1999/2000 Settlement	1999/2000 Tariff Application Phase I Negotiated Settlement.
2001/2002 TFO Settlement	2001/2002 Transmission Facility Owner Negotiated Settlement.
AEUB Act	*Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17.

TAB 6

Report
on

The Disposition Of Tax Savings On Disallowed Expenses

Submitted on behalf of

THE
COALITION OF ISSUE THREE DISTRIBUTORS

Kathleen C. McShane

Senior Vice President

Foster Associates, Inc.

January 12, 2005

I. INTRODUCTION

1. I have been retained by the Coalition of Issue Three Distributors to prepare a report on the disposition of tax savings arising from disallowed operating expenses and capital items. As part of this report, I will address the recommendations of Dr. Jack Mintz in his report entitled "*Corporate Tax Adjustments and the Determination of Electricity Rates in Ontario*" prepared on behalf of the School Energy Coalition (SEC). My qualifications are attached as Appendix A to this report.

2. My report is structured as follows:
   - Summary of Conclusions
   - Definition of Issues
   - Underpinning Regulatory Principles and Government Objectives
   - Application of Principles and Objectives to Specific Tax Savings Issues
     - Non-Recoverable and Disallowed Expenses
     - Excluded Capital-Related Costs
     - Gains and Losses on the Disposition of Utility Assets
   - Response to Report of Dr. Mintz

II. SUMMARY OF CONCLUSIONS

3. The key underpinning regulatory principles and governmental objectives to be followed in resolving the tax issues are:

   - "benefits follow costs"
   - the "stand-alone utility"
   - "level playing field"
   - "no harm" to ratepayers

4. The “benefits follow costs” principle holds that the stakeholder who has borne the costs should receive the benefits. If the shareholder incurs the costs, he should be entitled to any related tax savings. To allocate the tax savings to the ratepayer when the shareholder has borne the costs constitutes an unfair “double dip” for the ratepayer.

5. The stand-alone principle holds that only those costs and risks that pertain to the activities of the regulated utility in respect of the provision of service to ratepayers are reflected in the revenue requirement. The same principle should be applied to the income tax allowance. The stand-alone principle is widely accepted among utility regulators in Canada, including the Ontario Energy Board (OEB). To my knowledge, no Canadian utility regulator has adopted the stand-alone principle for all other cost categories in determining the revenue requirement and, then, abandoned it solely for the purposes of calculating the regulated utility income tax allowance.

6. The Government’s stated objective to create a level playing field through the Payments in Lieu of Taxes (“PILs”) requires that the income tax allowance for electric utilities that are subject to PILs be determined in a manner equivalent to that applicable to taxable utilities. To do otherwise will defeat the objective of PILs.

7. Disallowed operating expenses are, by their very nature, not part of the revenue requirement of the regulated utility and not borne by ratepayers. The “benefits follow costs” and stand-alone principles dictate that any tax savings generated by disallowed expenses go to the shareholders who incurred the expenses. The maintenance of a level playing field objective also dictates that the tax savings from disallowed expenses be received by shareholders, thus ensuring that no systemic rate advantage is held by PILs-paying distributors relative to taxable utilities.

8. With respect to excluded capital costs, customers do not bear the cost of any “excess” interest expense incurred as a result of the carrying value of assets on the distributor’s financial statements being higher than their original cost net book value rate base. Nor do

customers pay higher depreciation expense than is represented by the recovery of the original cost of the rate base assets. In consequence, ratepayers of the regulated utility are not entitled to the tax benefits that accrue to the legal entity as a result of a purchase of tangible utility assets at a price in excess of net book value (increased undepreciated capital cost and eligible capital expenditures).

9. The above conclusion is also fully consistent with the application of the stand-alone principle, which expressly excludes from the regulated utility's revenue requirement any operating or capital costs (or capital values) not deemed to be used to deliver regulated services. A proper application of the stand-alone principle similarly excludes any tax costs or benefits that are not part of the regulated utility.

10. The conclusion that the tax benefits flow to shareholders is also compatible with the objective of maintaining a level playing field, since the income tax allowance for taxable utilities excludes tax benefits related to capital costs not borne by the taxable utilities' customers.

11. The "no harm" principle states that a condition for approval of is "no harm to ratepayers". When neither the shareholder nor the ratepayer incurs any costs, but the shareholder gains a benefit, there is "no harm" or inequity to ratepayers.

12. The tax savings arising from the fair market value (FMV) adjustment required by the Ministry of Finance for tax purposes should also flow to shareholders on the basis of the stand-alone principle, the level playing field objective, and the "no harm" principle.

13. With respect to capital gains or losses upon disposal of utility assets, the *2006 Electricity Rate Handbook's* (Draft 2, January 10, 2005) ("Draft *Handbook*") proposed treatment of the tax savings or liability, that is, in the same way the accounting gain or loss is allocated, is appropriate. The proposed treatment is compatible with the "reward follows risk" principle that is widely used by regulators to allocate gains and losses between ratepayers and shareholders.

14. Dr. Mintz' recommendations, which entail passing all tax savings to ratepayers regardless of whether they have borne the corresponding costs, are inconsistent with all of the key regulatory principles which govern the calculation of the regulated utility income tax allowance. His recommendations contradict more than 25 years of regulatory precedent and practice, and should not be accepted by the Board.

III. DEFINITION OF ISSUES

15. Chapter 7 of the Draft *Handbook* describes the guidelines that are to be used for the determination of PILs that will be included in the revenue requirements of Ontario electricity distributors. A key issue is the treatment, for revenue requirement purposes, of tax savings that arise from operating and capital cost elements that are excluded from revenue requirements, for ratemaking purposes.

16. The Draft *Handbook* identifies the following items whose tax implications for revenue requirement purposes must be resolved:

- Distribution-only expenses that are deductible for general tax purposes, but are partially or wholly disallowed for ratemaking purposes (including any excess of actual over deemed interest expense);
- Specific expenses typically disallowed for revenue requirement purposes (e.g., certain advertising expenses);
- Increase in undepreciated capital cost (UCC) resulting from the purchase of tangible utility assets at a fair market value above net book value;
- Eligible capital expenditures with respect to disallowed capital (e.g., purchased goodwill);
- Increase in UCC or eligible capital expenditures with respect to the adjustment of assets to fair market value at October 1, 2001 as required for tax purposes by the Ministry of Finance; and
- Capital gains and losses on the disposition of distribution assets.

17. For each of these items, except capital gains and losses,[1] the Draft *Handbook* identifies three alternatives for the rate treatment of tax savings:

- 100% savings to ratepayers
- 100% savings to distributors
- Sharing of tax benefits between ratepayers and distributors.

The basic issue, then, is who should receive the benefit of tax savings that arise from each of the above items: the ratepayers, the distributors or some combination thereof? The resolution of this issue requires application of principles that should underpin (and have historically underpinned) the determination of utility revenue requirements.

IV. <u>UNDERPINNING REGULATORY PRINCIPLES AND GOVERNMENTAL OBJECTIVES</u>

A. <u>The "Benefits Follow Costs" Principle</u>

18. A key principle that should be applied is that the stakeholder who bears the cost is entitled to any related tax savings or benefit. If a cost is not included in the revenue requirement, then the ratepayer is not entitled to receive the benefits of the related tax savings. If the ratepayer does not bear the cost but nevertheless receives the benefit of the related tax savings, then the ratepayer achieves an unfair "double dip". In this unfair circumstance, the shareholder would not only bear the after-tax cost but would also face returns reduced by any related tax savings. A proposal to have the shareholder bear both the after-tax cost and the "cost" of related tax savings would place utilities regulated on this basis in an inferior position *vis-a-vis* that of unregulated competitive enterprises, whose expenditure and investment decisions are based on after-tax considerations.

[1] Capital gains and losses will be dealt with in the same way that the accounting gain or loss is allocated between ratepayers and distributors (Section 4.7 of the Draft *Handbook*).

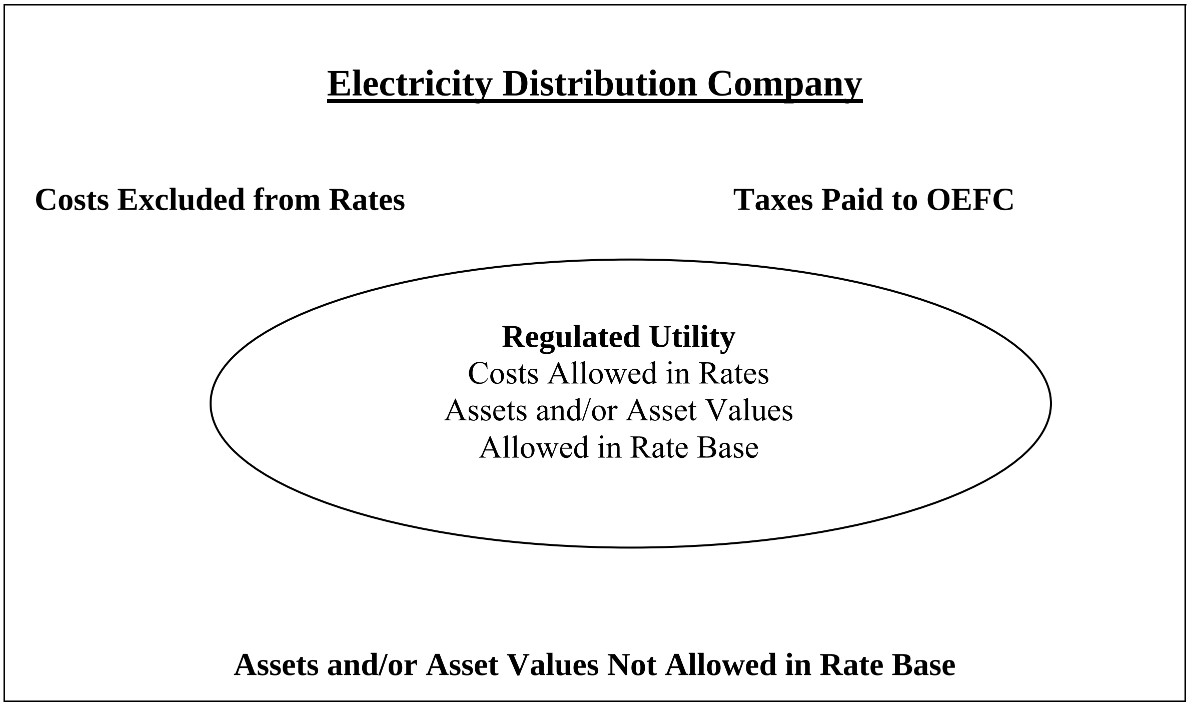
19. Stated another way, expenditure and investment decisions for unregulated competitive enterprises assume a sharing of risks between shareholders (the after-tax portion) and governments (the tax portion). Flowing through the tax savings that arise from utility costs that have been disallowed for ratemaking purposes would punitively assign the totality of the associated risks to the shareholder. This would be contrary to the proposition that regulation should act as a surrogate for competition.

20. Moreover, assignment of the tax savings to the ratepayer, with no corresponding cost burden, disregards the rules of fairness that govern the setting of regulated rates. The electricity distributors are entitled to the opportunity to earn a fair return on the rate base assets devoted to the public service. If the tax savings attributable to costs that are borne by shareholders are to the benefit of ratepayers, in whole or in part, the distributors are then denied the opportunity to earn a fair return.

B. Stand-Alone Principle

21. The stand-alone principle is a cornerstone of Canadian utility regulation. Adherence to the stand-alone principle requires that all costs incurred for the purpose of delivering regulated service be "carved out" from the total costs that are incurred by the entity that provides the regulated service. The costs that are required to provide regulated service and are approved for revenue requirement purposes can be characterized as stand-alone regulated utility costs. Costs that are incurred by the legal entity, but are not borne by customers, are, for ratemaking purposes, appropriately defined as non-utility costs.

22. The application of the stand-alone principle can be visualized through the following diagram.



23. The "box" in the diagram above represents the legal entity that holds all of the assets and incurs all of the costs. Not all of these assets and costs are incurred or used in the provision of regulated service(s). The setting of regulated utility rates requires that only those assets and costs incurred and used for regulated service be reflected in rates.[2] In effect, the regulated utility is carved out from the total operations of the legal entity.

24. In the diagram above, the regulated utility is represented by the "circle" within the "box". The costs and assets within the circle represent the stand-alone regulated utility. Only the costs and assets within the circle represent the elements that make up the revenue requirement. Adherence to the stand-alone principle means that only those costs, risks

[2] In this context, the assets used for regulated utility service include only the net book value that is allowed in rate base.

and benefits that arise from the provision of regulated service are borne by ratepayers. All other costs, risks and benefits incurred by the legal entity are to the account of the shareholder. The "carving out" of the stand-alone regulated utility ensures that subsidies are neither given to nor taken from other activities or actions of the legal entity that are not required for the provision of regulated service (that is, are "outside the circle").

25. The EUB describes the stand-alone principle as follows:

> "This first application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. <u>Using the stand-alone principle in this case, a utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged.</u> This application of the principle ensures that the revenue requirement of regulated utility operations is not influenced up or down by the operations of a parent or 'sister' company. <u>Thus the cost (or revenue requirement) of providing utility service reflects only the expenses, capital costs, risks and required returns associated with the provision of the regulated service.</u>" (emphasis added) (EUB Decision 2001-92, December 12, 2001, pp. 24-25).

Although the EUB describes the stand-alone principle in terms of the regulated utility versus a parent or "sister" company, the definition applies equally to a single legal entity, where the regulated utility ("the circle") is segregated from the legal entity ("the box").

26. The stand-alone principle has a long and rich history in the Canadian regulatory arena. Its earliest application can be traced to at least 1978.[3] It rose to prominence in regulatory decisions during the early 1980s.[4] Its application, which has been a staple of regulation,

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[3] Public Utilities Board of Alberta, Decision C78221, "In the Matter of The Alberta Gas Trunk Line Company Act", December 21, 1978, pages 19-27.

[4] The stand-alone approach to utility income taxes became the standard approach of the Federal Energy Regulatory Commission with *Florida Gas Transmission Co.*, 47 FPC 341 (1972). A full explanation of the FERC's rationale for its reliance on the stand-alone principle is found in Appendix B, *Columbia Gulf Transmission Company*, 23 FERC ¶ 61,396 (1983), pages 61,850-61,852.

has persisted uninterrupted to the present day[5]. The validity of the stand-alone principle was reaffirmed by the Ontario Energy Board as recently as 2004.[6]

27. Discussions of the stand-alone principle in regulatory decisions have frequently arisen in the context of cost of capital.[7] Adherence to the stand-alone principle requires setting a capital structure and cost of capital that reflect the risks of the regulated utility as a stand-alone entity ("the circle"), not those of the legal entity within which the regulated utility resides ("the box"). Adherence to the stand-alone principle is the premise underlying the practice of "deeming" hypothetical capital structures for the regulated utility in place of reliance on whatever might be the actual capital structure of the legal entity. The Ontario Energy Board has relied on deemed capital structures for the local gas distribution utilities it regulates since at least 1981.[8]

28. Most Canadian regulators rely on fully deemed stand-alone capital structures for the purpose of calculating the costs of capital to be included in utility revenue requirements.[9] Indeed, the stand-alone principle has been applied to the Ontario electricity distributors for the purpose of determining capital structure, cost of debt and allowed return on equity. Specifically, for revenue requirement purposes, the electricity distributors have been assigned deemed capital structures that vary with the size of rate base. The cost of debt to be recovered in each distributor's cost of service may range from a fully deemed

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[5] In RH-R-1-2002 (February 2003), the NEB stated, "The Board agrees with TransCanada that the stand-alone principle is a fundamental concept of utility regulation and a concept that it should continue to apply regulating TransCanada."

[6] In RP-2002-0158 (January 16, 2004), the Ontario Energy Board stated, 'A longstanding regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the stand-alone principle."

[7] Ontario Energy Board: EBRO 376-I & II (January 30, 1981), pp. 57-59, 61-70; EBRO 380 (September 14, 1981), pp. 51-59; EBRO 381 (January 27, 1982), pp. 59-62; EBRO 386-I (January 26, 1983), pp. 115-120; EBRO 397 (April 24, 1984), p.19.
National Energy Board: TransCanada PipeLines, RH-2-80 (August 1980), pp. 3-1 to 3-8, 4-17 to 4-22; Westcoast Transmission, RH-4-80 (November 1980), pp. 3-1 to 3-6, 4-1 to 4-5; TransCanada PipeLines, RH-4-81, Phase I (August 1981), pp. 3-8 to 3-9, 4-1 to 4-5, 5-9 to 5-13; TransCanada PipeLines, RH-3-82 (July 1982), pp. 3-1 to 3-9, 4-1 to 4-11; Westcoast Transmission, RH-1-83 (August 1983), pp. 31-36; TransCanada PipeLines, RH-R-1-2002 (February 2003), pp. 25-27;

[8] In EBRO 376-I & II (January 30, 1981), the OEB approved a stand-alone capital structure for Consumers Gas (now Enbridge Gas Distribution).

[9] British Columbia Utilities Commission, Alberta Energy and Utilities Board, Ontario Energy Board, Régie de l'Energie, National Energy Board.

rate, to a combination of deemed and actual rates, to an actual cost rate, with the approval of debt cost dependent on the cost and source of actual debt issued.

29. Application of the stand-alone principle through a hypothetical capital structure means that the rate base and capitalization of the stand-alone regulated utility are deemed to be equivalent for regulatory purposes. As a result, the actual amounts of invested capital (debt and equity) carried on the financial statements of the legal entity are largely irrelevant for revenue requirement purposes.[10] Only the costs of capital that are deemed to be financing the rate base are used to calculate amounts that will be recoverable from customers through rates.

30. Respect for the stand-alone principle in this context means that the interest expense included in the utility revenue requirement may differ from the actual interest expense incurred by the legal entity for some or all of the following reasons:

a. Utility assets on the legal entity's financial statements are valued at a cost higher than the net book value used to measure the rate base;
b. Utility assets on the legal entity's financial statements have been disallowed from rate base;
c. Interest expense on the legal entity's financial statements is incurred to finance both regulated and unregulated operations;
d. Actual capital structure ratios reflected on the legal entity's financial statements differ from deemed capital structure ratios for ratemaking purposes; and
e. Interest expense on the legal entity's financial statements reflects a cost rate for debt that differs from the cost rate the regulator determines to be compatible with the risks of the stand-alone regulated entity.[11]

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[10] The amounts of debt and equity on the balance sheet of the legal entity may be used to determine the regulated utility's capital structure ratios. The legal entity's cost of debt may be used as a proxy for the regulated utility's cost of debt.

[11] To illustrate, in Decision E92086 (1992), the Alberta Public Utilities Board reduced the cost rates on certain debt issued by NOVA Corporation for the purpose of financing the Alberta Gas Transmission Division (the predecessor of NOVA Gas Transmission Ltd.), on the grounds that the Alberta Gas Transmission Division could have issued that debt at a lower cost on a stand-alone basis.

31. Application of the stand-alone principle to capital structure and return on capital for revenue requirement purposes requires calculating an income tax allowance that similarly adheres to the stand-alone principle. Since interest costs are tax deductible, the income tax expense is a direct function of the debt ratio and cost of debt. The application of the stand-alone principle to the income tax allowance requires using the <u>same</u> interest expense included in the revenue requirement to calculate the corresponding income tax allowance. I know of no Canadian utility regulator who has applied the stand-alone principle to the cost of capital components of the revenue requirement but then abandoned that principle in determining the related income tax allowance.

32. In *Accounting for Public Utilities* (Matthew Bender: 2003), Robert Hahne and Gregor Aliff explain the rationale for reliance on a stand-alone income tax allowance in the context of jurisdictional vs. non-jurisdictional activities. The extract from the text provided below also explains how adherence to the stand-alone principle is compatible with the criterion that "benefits should follow costs."

> "In order to accept the argument for stand-alone tax allocations, the premise that the affiliated company that incurs the loss is entitled to the tax benefits that result must be recognized. The utility's jurisdictional customers have not paid any of the costs associated with the affiliate company that ultimately give rise to such tax benefits.
>
> If the utility's rates included provisions to pay for the costs of affiliated companies, then ratepayers would also be entitled to share in any resulting tax benefit. However, if the utility has appropriately excluded the costs of all nonjurisdictional activities in determining its jurisdictional revenue requirements, the ratepayer should not benefit from the resulting tax reductions. When nonjurisdictional activities are profitable, however, the jurisdictional ratepayers have no right to share in those profits, but neither should they be obligated to pay any of the income taxes that must be paid as a result of those profits.
>
> It is inconsistent and illogical to adhere to the basic regulatory principle of segregating jurisdictional and nonjurisdictional revenues and costs when setting rates, and to isolate one component of those costs, income taxes, for different treatment. However, if it is assumed that income taxes should receive some special treatment, jurisdictional ratepayers have no basis for the claim that they would be disadvantaged by not sharing in tax benefits attributable to

> nonjurisdictional activities when those ratepayers are not obligated to pay any costs attributable to nonjurisdictional activities.
>
> Furthermore, the expenses (deductions) of the nonjurisdictional operations are 'assets' to the extent that they can be used to offset taxes otherwise payable. To set a utility's jurisdictional rates based on any portion of these nonjurisdictional tax benefits not only involves allocating a benefit to ratepayers to which they are not entitled, but may also embody a use of assets of the nonutility entity for the benefit of ratepayers without compensation." (pp. 19-17 to 19-18)

The above discussion of "jurisdictional" versus "non-jurisdictional" activities and costs applies equally to the distinction between the activities and costs of the regulated utility as separate from those of the legal entity,[12] where "jurisdictional" is equivalent to the costs and assets in "the circle", and "non-jurisdictional" is equivalent to the costs and assets in "the box".

33. The applicability of the stand-alone principle to the income tax allowance was articulated by the National Energy Board (NEB) in toll proceedings of Westcoast Transmission (RH-4-80) and TransCanada PipeLines (RH-2-80 and RH-4-81, Phase I).

In RH-4-80 (Westcoast), the NEB discontinued the practice of tax benefit sharing in computing the income tax allowance, in favor of the stand-alone principle. As summarized by the NEB in its decision, Westcoast had argued that tax benefit sharing:

> "– causes ratepayers to receive one-half of the benefit of a tax deduction without paying the expense which gave rise to it;
> – results in cross-subsidization in that the tax expense to be paid by ratepayers is reduced below what it would otherwise be had non-utility investments not been made;
> – results in a permanent reduction in the return Westcoast earns on its non-utility investments;
> – retroactively alters the conditions assumed by the Company at the time the initial investments in non-utility operations were made; and
> – denies the same treatment to Westcoast's shareholders that is available to shareholders of other companies under the Income Tax Act." (p. 4-2).

[12] The excerpt from *Accounting For Public Utilities* refers to tax benefits generated by affiliate companies, which result from the requirement in the U.S. to file consolidated income tax returns, a practice that is not allowed in Canada.

34. In RH-4-80, the NEB concluded:

> "The Board has taken careful account of all evidence presented by both the Applicant and intervenors. The Board does not necessarily subscribe to all of the arguments advanced. However, the Board agrees with the weight given by parties to capital structure considerations and views the establishment of an appropriate capital structure as fundamental to the equitable resolution of the 'tax benefit sharing' issue. The Board has determined, as set forth in Chapter 3, a deemed capital structure, which it believes, at present, serves to minimize the pre-tax cost of capital to ratepayers and to avoid a subsidy to non-utility investments. In the circumstances of this case, it is the opinion of the Board that it would not be appropriate to order a tax treatment for ratemaking purposes which the evidence indicated, <u>inter alia</u>, could only benefit the ratepayers at the expense of the shareholders and would reduce the cost of service borne by ratepayers to a level below that which would have been the case had non-utility investments not been made.
>
> Accordingly, the Board approves the Company's request that the provision for normalized income taxes be computed in a manner which precludes 'tax benefit sharing'." (pp. 4-4 to 4-5).

35. For TransCanada, the NEB initially adopted the stand-alone approach to calculating the income tax allowance in RH-2-80.[13] The NEB decided to review the issue further in TransCanada's subsequent rate case (RH-4-81, Phase I) and concluded:

> "[It] is the Board's view that the evidence presented indicates that the ratepayers are effectively insulated from the cost effects of the Company's non-utility activities at the present time. Given that the costs of non-utility operations are not borne by the utility, given that no satisfactory method of the utility sharing in the 'synergy' has been placed in evidence and tested, and given that no adverse impact of the stand-alone concept on the utility is apparent at this time, it is the Board's view that, on balance, the equitable resolution of this issue lies in the acceptance of the Company's approach. The Board has decided, therefore, to compute the normalized tax allowance on the applied-for 'stand-alone' basis." (p. 5-12).[14]

36. The OEB also adheres to the stand-alone approach for determining the utility's income tax allowance and has done so since at least 1981. In E.B.R.O. 376-I & II, cited earlier,

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[13] See Appendix A for excerpt from RH-2-80.

[14] Complete discussion from RH-4-81, Phase I is included in Appendix B.

the Board rejected, on the basis of the stand-alone concept, the argument that there should be no income tax allowance in the utility revenue requirement of Consumers Gas because the legal entity of which Consumers Gas was then a division[15] would pay no income tax. (p. 58)

37. In E.B.R.O. 496 (Natural Resource Gas, August 1998), the OEB stated:

> "3.2.56 Board Staff submitted that it was standard regulatory practice to treat a utility as a stand alone entity for regulatory tax purposes. In Board Staff's opinion, NRG should be held to the same regulatory standard as other utilities. ….(p. 39)
>
> 3.2.59 The Board notes that the avoidance of cross-subsidization between regulated and non-regulated activities of a company or group of companies is a key principle in regulation. While there may be benefits to NRG from being part of the Graat group of affiliated companies, there are benefits to other entities within the group from the presence of NRG within the family. NRG's management fee compensates the Graat group of affiliated companies for any access to financing or management support provided. (p. 39)
>
> 3.2.60 Consequently, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the federal capital tax to be included in NRG's cost of service. ….(p. 40)
>
> 3.2.67 As previously stated, the Board is a strong proponent of the principle of avoidance of cross-subsidization. Consequently, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the income tax to be included in NRG's cost of service. ….(p. 41)
>
> 3.2.69 The Board also directs NRG to include in its filings for future rate hearings, a detailed calculation of the income taxes included in the Company's cost of service, showing any surtaxes that the Company must pay and any deductions to which the Company, considered on a stand alone basis, is entitled. (p. 41)
>
> 3.2.70 The Board holds that interest expense deductions allowed in determining NRG's taxable income must include the interest calculated on all components of the capital structure approved by the Board for rate making purposes. The Board therefore has incorporated the interest associated with the unfunded debt component of the capital structure in the net interest expense deducted in determining NRG's taxable income." (p. 41)

[15] At the time, Consumers Gas was a division of Hiram Walker-Consumers' Home Limited.

38. The OEB's documentation for the PILs proxy is also consistent with a stand-alone approach. Appendix B to the "Filing Guidelines for March 1, 2002 Distribution Rate Adjustments", dated December 21, 2001, states, "Provision for PILs will be assessed on a stand-alone basis, consistent with the Board's practice in the natural gas industry. Numerous other decisions have explicitly discussed and accepted the stand-alone principle in calculating the regulated utility income tax allowance."[16]

39. Respect for the stand-alone principle must be symmetric, applying to both costs and benefits. It cannot be applied in an *ad hoc* fashion but rather needs to be applied consistently across cost categories. Specifically, adherence to the stand-alone principle in determining the revenue requirement dictates exclusion of the costs and risks that are not incurred for the purpose of delivering regulated utility service. Exclusion of non-utility costs and risks from the revenue requirement, and thus utility rates, similarly requires exclusion from the revenue requirement of any tax benefits arising from those costs and risks.[17]

40. A review of regulatory precedents in Canada confirms that utility regulators' reliance on the stand-alone principle to require ratepayers to bear only the utility costs necessary to provide regulated service has been coupled with respect for the same principle in calculating the utility income tax allowance.

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[16] Ontario Energy Board, EBRO 456 (September 26, 1989), pp. 98-100; EBRO 485 (December 23, 1993), pp. 67-70. National Energy Board, Alberta Natural Gas, RH-1-80 (May 1980), pp. 6-1 to 6-3; Alberta Natural Gas, RH-1-82 (April 1982), pp. 3-6, 11-14; TransCanada PipeLines, RH-3-82 (July 1982), pp. 3-1 to 3-9, 4-1 to 4-11; Trans Québec & Maritimes Pipeline, RH-4-83 (March 1984), pp. 23-25; Trans Québec & Maritimes Pipeline, RH-2-90 (February 1991), pp. 16-18; TransCanada PipeLines, RH-1-91 (September 1991), pp. 19-21.

[17] The Texas Utilities Code (Section § 104.055(c)) specifies the linkage between costs to be included or excluded from utility rates and the corresponding tax expenses or deductions:

> "If an expense is allowed to be included in utility rates, or an investment is included in the utility rate base, the related income tax deduction or benefit shall be included in the computation of income tax expense to reduce the rates. If an expense is disallowed or not included in utility rates, or an investment is not included in the utility rate base, the related income tax deduction or benefit may not be included in the computation of income tax expense to reduce the rates. The income tax expense shall be computed using the statutory income tax rates."

C. <u>Government Objective of Maintaining a Level Playing Field</u>

41. In the context of utility ratemaking, the creation of a "level playing field" among regulated firms requires that no participant or group of participants have a systematic advantage over other participants.

42. The objective of achieving a level playing field was articulated by the Ontario Government in "*Direction for Change*", a report issued November 1997 prior to the introduction of the Energy Competition Act, 1998. The strategic plan delineated by the Province in that report includes, as a key objective, the creation of a level playing field for all participants in the electricity marketplace. The Government's plan envisions the Ontario electric utility industry, including the municipal electricity distributors, operating as commercial entities, and earning a normal rate of return for their shareholders.

43. As part of the creation of a level playing field, the electric utilities are to make payments in lieu of taxes (PILs) as if they were taxable entities. The stated objective in requiring PILs was not to create a stream of revenues to pay down the stranded debt of Ontario Hydro, although PILs will be dedicated to this purpose until the debt is extinguished. Rather the objective of PILs is to ensure fair competition; that is, a level playing field among all players in the industry.[18] To that end, the PILs will continue after the stranded debt of Ontario Hydro is eliminated. Instead of being remitted to the Ontario Electricity Financial Corporation (OEFC), the PILs will be remitted to the Minister of Finance.[19] By requiring the municipally-owned electric utilities to pay PILs, a systemic pricing advantage they would otherwise have relative to taxable utilities is removed.

44. The Government's objective of creating a level playing field extends to all participants in the energy industry and is therefore not limited to participants <u>within</u> the electric utility

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[18] Government of Ontario, Ministry of Energy, Science and Technology, "Direction for Change," November 1997, p. 21.
[19] Electricity Act, 1998, Section 93 (3).

industry. The Ministry of Energy published a Ministry Vision as part of its 2002-2003 business plan that proclaims its commitment to a level playing field, stating,

> "Through the ongoing work of the Ontario Energy Board, the Ministry is committed to an efficient regulatory system for both natural gas and electricity, one that creates a level playing field for competing energy sources in the Ontario economy."(p.1)

Consequently, in deciding the ratemaking treatment of the tax issues in this proceeding, the Government's objective of creating a level playing field among the regulated participants in the Ontario energy marketplace must be considered.

45. The municipally-owned utilities, while being tax exempt under Section 149(1) of the Income Tax Act (Canada), are effectively taxable as per the Electricity Act, 1998 and Ontario Regulation 162/01 (as amended), which subject them to the same rules as taxable regulated entities. Achieving the objective of a level playing field requires that the PILs recoverable in distribution rates be determined on the same basis as that applicable to taxable utilities.

46. The income tax allowance for taxable utilities is calculated on a stand-alone basis; that is, the income tax allowance is based only on the regulated utility costs approved for inclusion in revenue requirements. Similar treatment should be afforded the tax exempt utilities subject to PILs, so that regulated rates for both gas and electric utilities and for both taxable and tax exempt utilities are set on an equivalent level playing field basis. If, in contrast to taxable utilities, the tax savings generated by the non-utility operations or disallowed costs of tax exempt utilities are required to be flowed through to ratepayers, then the Government's level playing field objective will be thwarted.

D. <u>The "No Harm" Principle</u>

47. The "no harm" principle represents the minimum condition that must be met for a specific regulatory treatment for a utility asset sales transaction to be approved. That

minimum condition is that the treatment must result in no harm to ratepayers. The "no harm" principle, or standard, was defined by the Alberta Energy and Utilities Board (EUB) in Decision 2000-41 (July 5, 2000), as the Board "must be satisfied that customers of the utility will experience no adverse impact as a result of the reviewable transaction." This principle is widely applied throughout North America in evaluating utility asset sales transactions. The principle may also be extended into the ratemaking area, where neither the ratepayer nor the shareholder incurs a cost, but, nevertheless, the shareholder realizes a benefit. The OEB apparently applied the principle in this manner in its decision 376-I & II which permitted, in circumstances where there was no cost to either shareholders or ratepayers, benefits arising from the transaction to be retained by the shareholder. The decision held that, "The Board recognizes that the shareholders of the new corporation may enjoy benefits arising out of the amalgamation. The Board however agrees with Mr. Ryan that as long as such benefits are at no cost to utility customers, then there is no inequity."[20]

V. <u>APPLICATION OF THE PRINCIPLES AND OBJECTIVES TO SPECIFIC INCOME TAX ISSUES</u>

A. <u>Non-Recoverable and Disallowed Expenses</u>

48. The term "disallowed expenses" comprises a range of costs that a regulated firm incurs that are not approved for inclusion in the revenue requirement. These costs may include:

- charitable and political donations
- advertising expenses
- costs arising from certain incentive compensation plans
- company-specific operating and maintenance costs that may be disallowed by the regulator
- loss carry-forwards

[20] E.B.R.O. 376-I & II, January 30, 1981, p. 70.

Disallowed costs are not utility costs for purposes of establishing the revenue requirement and are therefore not borne by customers in rates. In the context of the "circle" in the "box" diagram introduced earlier, these costs lie within the "box" but outside the "circle".

49. The Draft *Handbook* expressly defines certain costs that are to be excluded from the electricity distributors' revenue requirements. For example, political contributions are to be excluded. Charitable contributions may be excluded in whole or in part, depending on resolution of the issue. Advertising expenses whose sole purpose is to promote corporate branding are excluded. Certain incentive compensation costs may be excluded if the incentives are tied to maximization of shareholder value. Consistent with avoidance of retroactive ratemaking, prior years' losses are not recoverable from ratepayers and are thus excluded from revenue requirements.[21]

50. While the expenses enumerated above are not recoverable from ratepayers by the regulated utility, they may be deductible for income tax purposes by the legal entity. The "benefits follow costs" principle dictates that the tax savings that result from the deductibility of the expenses should flow to the stakeholder who bore the costs. In each of these cases, that stakeholder is the shareholder. As stated earlier, passing the tax savings to the customers who have borne none of the corresponding costs allows those customers to an unfair "double dip".

51. Assigning the tax savings to customers is also contrary to the stand-alone principle, which has resulted in "carving out" those costs from the regulated utility. If the costs are not deemed to be stand-alone utility costs (and, therefore, not borne by utility customers), consistent application of the stand-alone principle requires that the utility income tax allowance also exclude the related tax savings.

[21] The Ontario electricity distributors have a limited ability to recover the costs of distribution investment or expenses that were not undertaken due to negative returns at the beginning of the Rate Design and Unbundling (RDU) process and/or did not receive the second third of the market adjusted revenue requirement or MARR (Tier 2 adjustments).

52. Finally, the rates of taxable utilities (e.g., the natural gas distributors) regulated by the Board exclude the tax savings that arise from costs that their ratepayers are not required to bear. The level playing field criterion requires equivalent treatment for the tax benefits arising from the disallowed expenses of the PILs-paying electricity distributors.

B. Excluded Capital-Related Costs

Excess Interest Expense

53. The Draft *Handbook* defines the rate base used to calculate the electricity distributors' revenue requirements. Rate base for the electricity distributors is defined as the original cost of utility assets inclusive of pre-2000 capital contributions less accumulated (book) depreciation plus a working capital allowance. The formula approach to capital structure, cost of debt and rate of return on equity set forth in the Draft *Handbook*, which uses a deemed capital structure and a debt cost rate that may be fully or partially deemed, explicitly excludes from the revenue requirement differences between actual financing costs and those deemed to be financing rate base.

54. The legal entity may be able to deduct for income tax purposes interest expense in excess of that allowed in the revenue requirement, but that "excess interest" should not be reflected in the utility income tax calculation. As I stated earlier, to my knowledge, no Canadian utility regulator has adopted a stand-alone regulated capital structure for revenue requirement purposes but then used a different capital structure to determine the utility's income tax allowance.

Purchase of Utility Assets

55. The purchase price represents the fair market value of the tangible assets plus any additional premium paid to acquire the business. With respect to the purchase of utility assets or businesses,[22] the purchased utility assets are accounted for by the acquiring legal

[22] As contrasted with the purchase of shares.

entity at their purchase price. The difference between the fair market value of the tangible assets and their corresponding net book value is allocated to these tangible assets. If the purchase price of the utility assets or business is higher than the fair market value of the tangible assets, the difference between the purchase price and the fair market value of the tangible assets is recorded as goodwill. The difference between the purchase price of the assets and their net original cost book value is referred to, in regulatory terms, as the acquisition premium. Regulatory practice generally disallows recovery of any of the acquisition premium from ratepayers.[23]

56. Electricity distributors in Ontario who have purchased utility assets at a price higher than net book value cannot recover those higher amounts from ratepayers, through either higher depreciation expense or amortization of goodwill.[24] Further, there is no recovery in rates through increased depreciation expense for the adjustment of the tangible assets to fair market value at October 1, 2001 as required by the Ministry of Finance for tax purposes.

Fair Market Value of Tangible Assets and Undepreciated Capital Cost

57. The legal entity that acquires utility assets can claim capital cost allowances that reflect the higher fair market value of the tangible assets (UCC, for income tax purposes). The opposite is true if the fair market value is below net book value; that is, the legal entity acquiring the assets at below net book value will have an undepreciated capital cost lower than what had previously been available to the entity selling the assets. Thus, in the latter case the purchaser will be entitled to lower capital cost allowances for income tax purposes than were available to the previous owner.

[23] Exceptions have been made in cases where the utility can demonstrate benefits to customers that equal or exceed the amount of the acquisition premium.
[24] The electricity distribution businesses were purchased by business corporations [Section 142 corporations] on or before November 7, 2000.

Goodwill and Eligible Capital Expenditures

58. Eligible capital expenditures, as indicated by Dr. Mintz' report, are the income tax analogue to goodwill. As indicated above, goodwill, as reflected on the legal entity's balance sheet, represents the difference between the purchase price of the business and the fair market value of the tangible assets. The legal entity that purchases the utility business at a premium above the fair market value of the tangible assets is able to take a tax deduction for the eligible capital expenditures associated with the premium.

Impact of Utility Asset Purchases on Ratepayers

59. The tax savings (or additional expense) that result from the purchase of utility assets at a price above (or below) net book value are created as a result of costs incurred by the purchaser to acquire the assets. Under most circumstances, a purchase price higher than net book value does not change the ratemaking value of the assets (i.e., the ratemaking value remains at net original cost book value). Thus, none of the costs of acquisition are borne by ratepayers. The depreciation expense in the stand-alone utility's revenue requirement does not change, nor does the return component of the revenue requirement. The return component remains equal to the allowed interest expense and return on equity deemed to be financing the net original cost book value rate base. The costs of any additional debt or equity that must be issued by the purchaser to acquire the utility assets at a price above net book value are borne by the purchaser; that is, the shareholder.

60. Consequently, when it is the shareholder who has borne the costs, it should be the shareholder who receives the benefits from the available tax deductions. The legal entity will be able to take increased capital cost allowances if the fair market value of the tangible assets is higher than net book value. However, the capital cost allowances that should be used to calculate the stand-alone regulated utility income tax allowance are those that ignore the impact of the purchase of utility assets. Since the ratepayers

incurred none of the cost of any premium expended to acquire the assets, they should not be entitled to the related tax benefits.

61. The stand-alone income tax allowance calculated for the revenue requirements of taxable utilities regulated by the OEB and other Canadian regulators does not include tax savings (costs) resulting from the purchase of utility assets at prices below or above net book value. From a level playing field perspective, the tax-exempt (but PILs-paying) electricity distributors should be afforded equivalent treatment.

62. In regard to this issue, the findings of the EUB in the case of TransAlta Utilities Corporation's sale of its electricity distribution business to UtiliCorp Canada Corporation (Decision 2000-41, July 5, 2000) support respect for both the "benefits follow costs" and stand-alone principles. In that case, TransAlta was proposing to sell its distribution business to UtiliCorp at a price that would result in both TransAlta incurring a terminal loss, and UtiliCorp recording an undepreciated capital cost that was considerably lower than UCC balances for the corresponding assets on the books of TransAlta. The EUB, in evaluating the proposed transaction, as a first condition, applied the "no harm" principle (p. 8). To ensure "no harm", the EUB conditioned its approval of the transaction on the maintenance of the pre-transaction balance of UCC for regulatory purposes. No additional taxes payable by UtiliCorp as a result of the lower UCC available to the legal entity due to the transaction were allowed to be recovered from customers.

63. The EUB further conditioned its approval of the transaction on a commitment from UtiliCorp that none of the purchase premium paid by UtiliCorp would make its way into the distribution rate base. Thus, the utility rate base would remain at net book value following the transaction and the calculation of the income tax allowance would continue as if no transaction had taken place. In other words, the same capital cost allowance would be used to derive the stand-alone utility income tax allowance for revenue requirement purposes that existed prior to the transaction.

64. In summary, regulatory practice ensures that ratepayers do not bear the costs related to the purchase of utility assets at prices different from net book value. The measurement of the rate base on which the investor is allowed the opportunity to earn a return remains at net book value irrespective of the price at which the regulated assets were purchased. The depreciation expense recoverable from ratepayers does not increase as a result of higher fair market values. Moreover, as evidenced by the EUB decision, utility ratepayers can not be burdened with increased income taxes that the legal entity may incur as a result of the purchase of utility assets. Symmetry of approach dictates that, when shareholders incur the purchase-related costs, they, not ratepayers, should receive the benefit of any higher capital cost allowances available to the legal entity.

65. Further, if the income tax savings arising from purchased goodwill are to the benefit of customers, a disincentive to further consolidation of the industry will be created. Clearly, the Ontario government has supported rationalization among the electricity distributors through a policy framework encouraging a voluntary approach to consolidation.[25] Passing the tax benefits of purchased goodwill to ratepayers will lower the market value of the electricity distribution business. In turn, municipalities will be less willing to sell their businesses which will, in turn, discourage further consolidation within the industry.

Fair Market Value "Bump Up"

66. The specific case of the adjustment to fair market value (FMV) required by the Ministry of Finance for tax purposes represents a unique circumstance in which tax savings were created without any corresponding costs incurred by either shareholder or ratepayer. In resolving the issue of which stakeholder should receive the tax benefits, the "no harm" principle should be considered. The principle, as applied to the issue of the FMV "bump up", ensures that customers are not harmed by flowing the tax savings to shareholders. The FMV "bump up" does not change the rate base, the interest expense, the return on equity or depreciation expense borne by customers in distribution rates. Thus, the FMV

[25] Ontario Ministry of Energy, Science and Technology, *Electricity Transmission and Distribution in Ontario – A Look Ahead*, December 21, 2004.

"bump up" has not altered the regulated utility costs that comprise the distribution revenue requirement. Since customers have borne no costs in the revenue requirement that are associated with the FMV adjustment, there is necessarily "no harm" to customers if the tax savings from the FMV adjustment flow to the distributor. A finding of "no harm", and flowing the FMV adjustment savings to customers, is compatible with the OEB's findings in EBRO 376-I & II referenced in paragraph 47 above.

67. The stand-alone principle gives further support to a finding that the ratepayer has no entitlement to the tax benefits: the regulated utility's revenue requirement includes no costs related to the FMV adjustment (i.e., there are no costs related to FMV "in the circle").

68. The FMV "bump up" for the electricity distributors parallels the income tax "fresh start rule" that applies to non-taxable corporations which become taxable. The FMV "bump up" is intended to be the equivalent "fresh start" as applied to tax-exempt utilities when they become PILs-paying utilities. In other words, the FMV "bump up" was intended to mimic the corresponding element of the Income Tax Act (Canada), as part of the Government's effort to create a level playing field. In consequence, the level playing field criterion also indicates that there is no ratepayer entitlement to the tax savings from the FMV "bump up". No taxable utility under the OEB's jurisdiction has been subject to a similar adjustment. Thus, taxable utilities' rates necessarily exclude an equivalent tax benefit.

C. <u>Gains and Losses on the Disposition of Utility Assets</u>

69. The Draft *Handbook* states that the treatment of capital gains and losses on both depreciable and non-depreciable distribution assets sold to a non-affiliate will be determined on a case-by-case basis, subject to a materiality threshold. For depreciable assets, capital gains and losses below the threshold will be borne by the shareholder; for non-depreciable assets, capital gains and losses that fall below the materiality threshold will be shared between ratepayers and shareholders on a 50/50 basis in determining the

utility's revenue requirement. The Draft *Handbook* also indicates that, for the purpose of estimating the PILs to be included in the revenue requirement, any portion of the disposal of distribution assets that generates a taxable gain or allowable capital loss will be dealt with in the same way the accounting gain or loss is allocated between ratepayers and distributors.

70. The regulatory precedents for the ratemaking treatment of capital gains and losses in Canada and the U.S. can be summed up, somewhat facetiously, in two words: "it depends." Regulators' decisions on the disposition of capital gains and losses are most frequently tied to the proposition that "the reward should follow the risk." That proposition is roughly equivalent to "benefits follow costs." The OEB's draft Background Policy Paper entitled "*Understanding the Proposed Amendments to the Affiliate Relationships Code for Gas Utilities"* (March 15, 2004) states:

> "A review of the general rates treatment of capital gains from the sale of utility assets indicates that the following are the most common starting points: 'The first principle is that the right to gain follows the risk of loss. The second is economic benefits must follow economic burdens.'" (p. 19)

71. Thus, individual circumstances may warrant different allocations of gains or losses. The draft Background Policy Paper briefly reviews the arguments that have been made in support of which stakeholder should bear the gains and/or losses from depreciable and non-depreciable assets, and summarizes the Board's own past decisions as follows:

> "Past Ontario Energy Board decisions on the treatment of capital gains have placed varying weight on specific considerations. In recent years (see especially E.B.R.O. 465 in 1991), the Board has favoured a 50/50 sharing of the gains between ratepayers and shareholders." (p. 20)

72. Recent decisions of the EUB illustrate how different circumstances can lead to different allocations. With respect to the sale of TransAlta Utilities Corporation's entire distribution business to UtiliCorp Canada, the EUB determined that,

> "[A] fundamental principle of the regulatory compact is that the distribution of a gain or loss on the sale of a utility asset should be allocated based on who took the financial risk associated with the asset. In a free market all financial risk rests with the owner and as a consequence the owner will gain or lose according to market value fluctuations. …..
>
> Of course TransAlta is rate regulated and under the regulatory compact some of the risks normally borne by the free market owner are borne by customers.
>
> In the case of a sale of an operating utility business, one of the risks is that the purchase price will exceed or be less than the value of the system on the vendor's books, thus creating an accounting gain or loss. In jurisdictions such as Alberta where rate making is based on the original cost of the assets (less accumulated depreciation) rather than market value, the risk of a loss consequent upon the sale of the business falls on shareholders. In contrast, ratepayers are shielded from fluctuations in market value because rates are based on original cost less accumulated depreciation. Viewed another way, if customers are to receive the benefit of the difference between fair market value and original cost in their circumstances, they should also bear the concomitant risk of paying rates based on the fair market value of the assets. Moreover, as the Board will require in this case, customers are shielded from increases in the rate base because the new owner is prevented from including the premium over book value in rate base. Finally, relative risk as between shareholders and customers is maintained in a case such as this one because customers continue to receive the same service from the same assets which remain in rate base at the same value as prior to the sale of the business.
>
> In these circumstances, therefore, where the entire utility business is being sold as a going concern from one regulated utility to another, the Board considers that the regulatory compact is preserved and gains or losses on sale should, as a general rule, accrue to shareholders." (Decision 2000-41, July 5, 2000, pp. 28-29)

73. In a later decision respecting the sale of specific assets (both depreciable and non-depreciable) out of rate base, the Board determined that,

> The Board considered evidence, written authorities and arguments from parties regarding the ratios of allocation of the net gain on the sale of the assets. The parties argued a range of allocations that varied from 100% of gain to the company to 100% of gain to customers while referencing a variety of cases in many jurisdictions. The Board observed that each case was evaluated on its own specific set of circumstances and resulted in a percentage net gain allocated between customers and companies that varied from cases to case.

> In balancing the interest of the customers' desire for safe reliable service at a reasonable cost with the provision of a fair return on investment made by the company, the Board considers that the interests of both parties must contribute to the business environment. Both parties' interests should contribute toward the factors affecting decisions made by the company.
>
> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.
>
> The Board believes that some method of balancing both parties' interests will result in optimization of business objectives for both the customer and the company. Therefore, the Board considers that sharing of the net gain on the sale of the land and buildings collectively in accordance with the TransAlta Formula[26] is equitable in the circumstances of this application and is consistent with past Board decisions." (EUB Decision 2002-037, March 21, 2002, pp. 23-24)[27]

74. The OEB's draft Background Policy Paper and the two decisions of the EUB indicate that the application of the "reward follows risk" principle to different circumstances may call for different allocations of capital gains and losses between ratepayers and companies. If a regulator has evaluated a particular transaction and has determined that the gain or loss belongs to a particular stakeholder in its entirety, or is to be shared between ratepayers and company, the logical extension of that decision is that the income tax implications should attach to the same stakeholder. If the regulator allocates a gain 50/50 between ratepayers and shareholders, assignment of 100% of the associated income tax liability to the ratepayers unfairly reduces their intended allocation. The Draft *Handbook's* proposed

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[26] The TransAlta Formula first allocates from the Net Proceeds the Net Book Value (NBV) to the utility and the Accumulated Depreciation (AD) to customers. The remainder to be shared, if any, is then allocated as follows:

Company: (Current Dollar Index x NBV) – NBV
Customers: (Current Dollar Index x AD) – AD,
Where Current Dollar Index $= \frac{\text{Net Proceeds}}{\text{Original Cost}}$

[27] The Alberta Court of Appeal vacated this decision on jurisdictional grounds (January 27, 2004); the Court's decision is under appeal to the Supreme Court of Canada. Decision 2002-037 nevertheless sets out the principles applied by the EUB when allocating gains or losses from the sale of utility assets.

treatment of the tax costs or savings associated with the capital gains or losses is entirely compatible with the "reward follows risk" or "benefits follow costs" principle, and should be adopted.

VI. RESPONSE TO EVIDENCE OF DR. MINTZ

75. Dr. Mintz' position can be summarized as follows:

a. Dr. Mintz concludes that the burden of corporate taxes most likely falls on consumers, although he admits that a clear case has not been made for whether the burden falls on consumers, employees or shareholders.
b. Regulation treats tax payments as a cost of doing business, and corporate taxes in general are viewed as recoverable costs for ratemaking purposes. Thus, all tax savings generated by the regulated entity should be passed through to customers in lower rates.

76. In sum, Dr. Mintz concludes that the regulated utility income tax allowance for ratemaking purposes should follow the income tax calculation of the legal entity. Dr. Mintz' recommendations are inconsistent with the basic principles that underpin utility ratemaking in North America.

77. Dr. Mintz' recommendations are inconsistent with the principle of "benefits follow costs", because his approach would give all tax savings to ratepayers regardless of whether they have borne the costs that gave rise to those savings. Implementation of Dr. Mintz' recommendations would allow ratepayers an unfair "double dip", first through the exclusion of the cost from the revenue requirement and second from receipt of the benefit of the cost's corresponding tax savings. For example, regulatory practice prohibits the regulated utility from recovering from customers any excess of price above net book value paid for utility assets. Dr. Mintz' approach would, nevertheless, pass the legal entity's associated tax savings to those customers.

78. With respect to capital gains and losses, Dr. Mintz recommends that the ratepayer either absorb, through higher rates, the additional taxes that result from the legal entity's obligation to pay capital gains tax or receive the benefit, through lower rates, of a reduction in taxes should the legal entity incur an allowable capital loss. This proposal, on its face, is illogical. If the OEB should determine that the ratepayer is entitled to 50% of the gain, but is responsible for 100% of the related capital gains tax, then the benefit that the OEB intended for the ratepayer is unfairly reduced.

79. Dr. Mintz' recommendations also violate the stand-alone principle. His recommendations essentially presume that the Board is setting rates based on all the costs in the "box", when in fact, the Board is only regulating the "circle". Dr. Mintz' approach ignores over 25 years of precedent and practice which have established and maintained the stand-alone principle as a cornerstone of Canadian regulation.

80. Finally, Dr. Mintz' approach is inconsistent with the Government's objective of maintaining a level playing field among energy industry participants. For example, his recommended approach would set the rates of the electricity distributors on a basis different from that applicable to the gas distribution utilities in Ontario. If all tax savings are passed through to customers, whether or not the customers have borne the associated costs, then, all things equal, the electricity distributors' rates will be systematically lower relative to those of the gas LDCs. The express purpose of PILs was to help achieve a level playing field. Dr. Mintz' approach would defeat that purpose.

81. Dr. Mintz' report also suggests that a further reason for passing the tax savings to customers is that neither the distribution companies nor their customers are better or worse off. For the distribution companies, Dr. Mintz claims they will be no worse off because they pass on the taxes in rates. In the case of customers, Dr. Mintz states that the lower rates resulting from lower PILs will produce higher Debt Retirement Charges (DRCs), dollar for dollar.

82. Dr. Mintz is incorrect when he says the distributors will be no worse off. The distribution companies cannot pass on in rates the <u>costs</u> that give rise to the tax savings. If the distributors are not allowed to retain the tax savings corresponding to costs they cannot recover from customers, they necessarily will be worse off. In fact, they will be denied the opportunity to earn a fair return, violating a central tenet of the regulatory compact.

83. PILs and the DRCs cannot be viewed as interchangeable. As noted earlier, PILs were introduced for the purpose of a level playing field among energy market participants, and should be treated as such by the OEB. Thus, the PILs allowance should be determined in the same manner as the stand-alone income tax allowance of taxable utilities.

84. The DRC was designed by the Government specifically to recover Ontario Hydro's stranded debt. It is not set or administered by the Board, but by the Government, which has the authority to change or eliminate the DRC. Any changes in the DRC would not alter the PILs, whose existence relates to the objective of a level playing field. As noted earlier, PILs will continue even after the stranded debt is extinguished. The fact that the PILs are currently dedicated to paying down stranded debt does not alter the principles that should govern the determination of the stand-alone regulated utility PILs allowance.

85. For all of the above reasons, the OEB should reject the recommendations of Dr. Mintz and should continue to compute the allowance for income taxes in a manner that is consistent with the "benefits follow costs" principle, the stand-alone principle, the "no harm" principle, and the Government's objective of maintaining a level playing field.

APPENDIX A
QUALIFICATIONS OF
KATHLEEN C. McSHANE

Kathleen McShane is a Senior Vice President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder (since 1989).

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 125 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- "Utility Cost of Capital Canada vs. U.S.", presented at the CAMPUT Conference, May 2003.

- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several Commissions and Universities, April 1998.

- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

- "Market-Oriented Sales Rates and Transportation Services of U.S. Natural Gas Distribution Companies", (co-authored with Dr. William G. Foster), published by the IAEE in *Papers and Proceedings of the Eighth Annual North American Conference*, May 1987.

- "Canadian Gas Exports: Impact of Competitive Pricing on Demand", (co-authored with Dr. William G. Foster), presented to A.G.A.'s Gas Price Elasticity Seminar, February 1986.

- "Marketing Canadian Natural Gas in the U.S.", (co-authored with Dr. William G. Foster), published by the IAEE in *Proceedings: Fifth Annual North American Meeting*, 1983.

Expert Testimony/Opinions

on

Rate of Return & Capital Structure

Alberta Natural Gas	1994
Alberta Power/ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
AltaGas Utilities	2000
Ameren (CIPS and & Union Electric)	2000 (3 cases), 2002 (3 cases) 2003
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
BC Gas	1992, 1994
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1996
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic ROE Proceeding in Alberta (ATCO Utilities and AltaGas)	2003
Heritage Gas	2002
HydroOne/Ontario Hydro Services Corp.	1999, 2000
Illinois Power	2004
Insurance Bureau of Canada (Newfoundland)	2004

Laclede Gas Company	1998, 1999, 2001, 2002
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002
Newfoundland Telephone	1992
Northwestel, Inc.	2000
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001
Nova Scotia Power Inc.	2001, 2002
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions

on

Other Issues

Client	Issue	Date
Caisse Centrale de Réassurance	Collateral Damages	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Consumers Gas	Principles of Cost Allocation	1998
Enbridge Consumers Gas	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

APPENDIX B

STAND-ALONE PRINCIPLE
Excerpts from Regulatory Decisions

National Energy Board of Canada, Reasons for Decision RH-2-80, TransCanada PipeLines Limited, August 1980, pages 4-17 to 4-19

"(b) Equity Method for Calculating Income Taxes

In its current application, the Company included an amount of income taxes which reflected the equity method of computation. The significance of this method is that the income tax provision to be included in the cost of service is essentially based on the common equity return without taking into account interest expense not recovered in the return on rate base or other expenses allocated to non-utility activities and not recovered in the cost of service. In the circumstances of this case, the Board accepts the applied-for method.

(c) Interest on Debt Used to Acquire Non-Utility Property

As a result of financing its diversification program, the Company's total interest expense exceeds the interest component of the return on rate base. The Company has requested that any interest expense not collected in the cost of service be excluded from the determination of income taxes for rate-making purposes.

This request was a contentious issue in this hearing. On the one hand, intervenors argued that income taxes for rate-making purposes should reflect all or part of the non-collected interest expense because TransCanada has no sources of taxable income other than its pipeline operation which might be reduced by the application of this interest expense; that the credit capacity of TransCanada's pipeline operation had formed the basis upon which the diversification program was financed; that the diversification might affect the Company's credit rating or financing costs in a negative way; and that past Board decisions have reflected all or part of similar interest expenses in the computation of income taxes for rate-making purposes.

The Applicant, on the other hand, argued that the non-collected interest costs were not borne by the ratepayers and, therefore, the ratepayers are not entitled to the benefit of the tax deduction associated with this interest; that the shielding of the shareholders' income by this interest expense was in keeping with provisions of the Income Tax Act designed to encourage equity investment by Canadian corporations in other Canadian corporations; that the credit capacity of the pipeline operation rested ultimately with the capital invested and reinvested by the Company's shareholders; that to compute the income taxes for rate-making purposes on a basis other than the one applied for could only benefit the ratepayers and have a negative impact on the shareholders; and that the calculation of income taxes for rate-making purposes on the basis requested would place the ratepayers in exactly the same position as they would have been had no diversification taken place.

Having regard to all of the evidence presented, and particularly to the deemed capitalization, which includes a 30 percent common equity ratio, the Board has decided that the computation of income taxes for rate-making purposes should not include interest expense that is not recovered in the approved return on rate base."

National Energy Board of Canada, Reasons for Decision RH-4-81, Phase I, TransCanada PipeLines Limited, August 1981, pages 5-9 to 5-12

"(ii) <u>'Stand-Alone' Approach to Computing Income Taxes</u>

In its 1980 Rates Application, TransCanada, having embarked upon a substantial investment program unrelated to its jurisdictional utility operations, requested that the normalized tax allowance to be included in its cost of service reflect only those items of revenue and expense which it considered applicable to its utility operations.[1/] As a matter of terminology, this applied-for approach was said to be of a 'stand-alone' nature and was embodied in the so-called equity method of calculating income taxes. This approach was accepted in a majority decision of the Board, on the basis of evidence put forward at that time.

By a letter to TransCanada dated 19 June 1981, the Board expressed the desire to give further consideration to the issue of whether the provision for income taxes should be calculated on the 'stand-alone' basis or whether, and to what extent, the provision for income taxes in the cost of service might take into account the tax position of the corporation as a whole.

The issue at hand centers essentially on the fact that TransCanada has available to it tax deductible expenses[2/] which are associated with its non-utility activities and which can be used by the Company at this time to offset revenues derived from its utility operations in computing the income taxes payable by it as a corporation. This occurs because the Company's non-utility activities basically comprise investments in the shares of other corporations, the dividend income from which is not subject to tax in TransCanada's hands. Thus, in filing its tax return, TransCanada, through the application of such expenses to revenues derived from its pipeline operations, may reduce the taxes actually paid by it as a corporation below that level collected from ratepayers on a 'stand-alone' basis.

In response to the Board's notice, TransCanada reaffirmed the position it took in the 1980 proceedings, arguing that the ratepayer should neither bear the costs nor enjoy the benefits associated with its non-utility activities. The Company continued to assert that measures had been taken, and were in place, (e.g. a deemed capital structure and divisionalized accounting for overhead costs) which effectively insulated the ratepayer from the costs of diversification and, therefore, that it would be inequitable for the ratepayer to receive any of the diversification benefits. The Company expanded upon this position by putting forward several specific arguments including the following:

- where costs are not recoverable in the Company's tolls and it would be inequitable for the ratepayer to receive the benefit of the associated tax deduction without at the same time being required to pay the underlying cost;

- to accept the applied for 'stand-alone' approach would simply place the ratepayers in the same position as they would have been had no diversification taken place;

- the appearance that the cost of service tax allowance may be too high is nothing more than that, provided one chooses to look through the intercorporate investment to consider the expenses incurred by the investing company as having been incurred by the investee and as having the present or future potential of reducing that entity's taxable income;

- to reduce the cost of service tax allowance through the use of such expenses would be inequitable in that the ratepayer could receive a benefit only at the expense of the shareholder; and

- since a stand-alone approach has been adopted for all of its other costs, to take a non-'stand-alone' approach with respect to income tax costs would be inconsistent and require a wholly arbitrary approach in deciding the quantum of non-utility associated tax deductions to be reflected in the cost of service tax calculation.

While the term ‘stand-alone’ as typically used by TransCanada refers to a separation as between its utility and non-utility activities of costs which are of a relatively tangible and allocable nature, the evidence presented during the course of the hearing made clear the fact that the non-utility activities benefit from the existence of the utility because:

- the Company’s jurisdictional pipeline operations provided a base which served to enable or facilitate the financing of its non-utility ventures; and

- the Company’s jurisdictional pipeline operations in fact provide the essential revenue stream against which the non-utility tax deductions are applied, thus giving value to those deductions by assuring their early recovery.

Both of the preceding factors point to the existence of a synergistic effect created by combining utility and non-utility operations in a single corporation. To this extent, they also demonstrate that the relative position of the non-utility operations might be substantially less favourable had they been undertaken directly in separate corporations rather than through the medium of intercorporate investments chosen by TransCanada.

Nevertheless, it is the Board’s view that the evidence presented indicates that the ratepayers are effectively insulated from the cost effects of the Company’s non-utility activities at the present time. Given that the costs of non-utility operations are not borne by the utility, given that no satisfactory method of the utility sharing in the ‘synergy’ has been placed in evidence and tested, and given that no adverse impact of the stand-alone concept on the utility is apparent at this time, it is the Board’s view that, on balance, the equitable resolution of this issue lies in the acceptance of the Company’s approach. The Board has decided, therefore, to compute the normalized tax allowance on the applied-for ‘stand-alone’ basis.”

1/ As an extension of this request, TransCanada also submitted that the average deferred tax balance to be deducted from rate base be calculated on a ‘stand-alone’ basis. The Board accepted this approach as it did that pertaining to normalized taxes.

2/ These fall primarily into three categories: interest expense incurred to finance non-utility investments; Canadian Exploration and Development Expenses renounced to TransCanada by its subsidiary TCPL Resources; and various overhead costs allocated to non-utility activities.”

"**V.**

For us, a rate for a gas pipeline or an electric utility is "just and reasonable" when it is cost-justified. That is, the rate should be set so as to allow the company the opportunity to recover the expenses it incurs in providing service and earn, after paying taxes, the allowed rate of return.

That is easy enough to say. But the cost-based standard is difficult to apply. Among the problems is simply the determination of the costs incurred in providing service.

The amounts the company records in its books for the year are the starting point. But they are a starting point only. These amounts often do not reflect the costs incurred in providing service during the test year. The amounts may reflect payments for services that were performed earlier or that will be performed later or that benefit other services separately regulated by us, by other regulatory commissions, or that are not regulated at all. And where the company is part of an affiliated group, the amounts recorded on the company's books may reflect payment for services performed for its siblings. Or the company's books may not reflect the expenses its siblings have incurred for the benefit of the ratepayers.

In all these cases the "problem is to allocate to each class of the business [and to each time period and each company] its fair share of the costs."[9/] We have developed a number of methods for doing that. These methods vary with the expense at issue and the problem presented. Some are simple and straight-forward. Others are complex and subtle.

Despite the profusion of allocation methods we employ, there is a common thread that ties them together. That thread is the concept of cost responsibility or cost incurrence.[10/] Each of the methods attempts to allocate costs to the group of ratepayers in question on the basis of a causal link between the service the company provides them and the expenses the company reports. That this is a fair method of allocation is self-evident. And it limits the allowance for expenses to the costs associated with the goods and services provided in the period.

Taxes are no different from other expenses included in the cost of service. So there should be no difference between the principles used to determine the tax allowance and the allowances for other expenses. And we make no distinction. In both cases we limit the allowance charged to ratepayers to an amount equal to the costs the company incurs in serving them. But the application of these principles is a little different in the case of taxes.

The need for a different application of the principles stems from the fact that the income tax is not simply a tax on income. It is a tax on profits, which is gross income less the expenses incurred in producing income. So the tax allowance should be equal to the tax on the profit the ratepayers will contribute to the company. In short, the tax allowance should be equal to the tax on the company's allowed return on equity.[11/] This is so because the allowed return on equity is the amount of profit the company should receive for providing service to the ratepayers.

There are, however, vast differences between our assessment of the profit the company is due and the calculation of the amount by which the company is considered to have been enriched by the Internal Revenue Service. Some of these differences stem from the differences in the revenue that is used in calculating the company's profit. The most obvious difference is that we base our determination of the company's profit on projections of revenue. The Internal Revenue Service uses, of course, the revenues the company either actually receives or accrues the right to receive during the tax year. There are even greater differences in the expenses that are recognized.

Because these differences are so vast, the Commission has found that the taxes the company pays to the Internal Revenue Service are not a reliable guide, even as a starting point, for determining a company's tax allowance. Instead, the Commission has always made its own assessment of the tax cost the company incurs in providing service.

We make that independent assessment by considering the two elements that go into the calculation of taxes-income and expenses-separately. We start by determining the income we expect the company to receive from the particular service in question. There is usually no problem with this. We then consider the deductions from income. This requires an allocation, for just as the expenses recorded in the company's books may be for services performed for different periods or different classes, so also with the deductions reported on the tax return. Here again we allocate on the basis of the customers' responsibility for the deductions.

Because deductions are given for expenses incurred in producing income, the necessary causal link between the ratepayers and the deductions is the expenses the company incurs in providing service. Accordingly, the proper way to allocate deductions is to match the deductions with the expenses included in the cost of service. Thus, when an expense is included in the cost of service, the corresponding tax deduction is also allocated to the ratepayers. In this way any tax reducing benefits, or savings, the company realizes in providing the service are recognized in calculating the tax allowance for the benefit of the ratepayers.

The corollary to this is that when an expense is not included in the cost of service (because the company did not incur that expense in providing service), the deduction created by that expense is not allocated to the ratepayers. To do otherwise would result in the tax savings the company realizes from expenses incurred in providing services to other groups and periods or for its own benefit being used to reduce rates for a particular group of ratepayers. The tax allowance would then be lower or higher than is warranted by the profit each group provides the company. Since the amount of profit to be provided is the measure of the tax cost the company will incur in providing service, none of the rates for the groups would be cost-justified. Subsidization would inevitably result. One group would bear the burden, but another group would gain the benefit.

VI.

So much for theory. What of its application to the case? How does the method the pipelines have used stack up against this standard?

The short answer to these questions is that the method the pipelines have used stacks up very well. It produces an allocation of the consolidated tax liability that is cost-justified and just and reasonable.

The method the pipelines have used, and the method the Commission has followed since 1972, is one in which "a utility [is] considered as nearly as possible on its own merits and not on those of its affiliates."[12/] This method is called the stand-alone method, for "a stand-alone income tax allowance is one that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities . . . "[13/] The stand-alone method results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. In short, it results in a tax allowance equal to the tax on the allowed return on equity.

The mechanics of calculating a stand-alone tax allowance are as follows: From the total return allowed on rate base are deducted interest expenses (computed by multiplying the rate base by the weighted cost of long-term debt used in determining the rate of return), permanent tax differences, and the effect of the surtax exemption to arrive at the tax base. The tax base is then multiplied by the factor of 48% over 52% (now 46% over 54%) to produce the tax allowance, which includes recognition of the fact that the tax allowance itself is subject to tax when received by the utility and is not deductible. The amount so calculated is the tax allowance.

That the mechanics of calculating a stand-alone tax allowance do not take into account the revenue received and deductions for operating and maintenance expenses is not important. In calculating the tax allowance our policy is that a legitimate expense for cost of service purposes is to be considered to be a legitimate deductible expense in calculating a company's cost of service tax allowance.[14/] Accordingly, we can safely ignore the utility's operating and maintenance expenses and the revenues needed to recover those expenses. The only area for concern is the return on rate base."

[9/] Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581, 591 (1945).

[10/] See e.g., Utah Power & Light Company, Opinion No. 113, 14 FERC 61,162, at p. 61,298 (1981), where the Commission said that it "must allocate costs in a manner which reflects cost incurrence."

[11/] This is somewhat of an oversimplification. The calculation is slightly more complicated. See infra p. 11. But we need not address these refinements here.

[12/] Florida Gas Transmission Company, Opinion No. 611, 47 FPC 341, 363 (1972).

[13/] Exh. 11 at 4.

[14/] This policy is most familiar from our rulemaking on tax normalization. Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes, Order No. 144 , FERC Statutes and Regulations 30,254 (1981), reh. denied, Order No. 144-A , FERC Statutes and Regulations 30,340 (1982), aff'd sub nom., Public Systems v. F.E.R.C., Nos. 82-1183 et al. (D.C. Cir. May 31, 1983).

TAB 7

Decision **2011-399**

Alberta Utilities Commission

EPCOR Distribution & Transmission Inc.

Determination of Whether an Audit of Corporate Costs is Required

October 7, 2011

40. One way to do so is to envision how the competitive market would behave if there were a situation similar to the present set of facts. Consider two firms A and B. They sell ice-cream and hamburgers. It turns out that A and B can sell their wares in one physical location as customers who like hamburgers also like ice-cream. If A and B merged, they would be able to save on the rental overhead, since they now can rent one space instead of two. The average rent per unit sold of ice-cream or hamburger can now be halved, thereby giving the newly merged firm a competitive advantage over its rivals. If, after many years, A and B decide their marriage is no longer amicable, either due to changing market conditions or simply managerial conflicts, the two may decide to split. In doing so, however, they now face the prospect of having to each rent a separate physical location to sell their products. This will mean that the newly un-merged firms A and B will have to either raise their prices or absorb the increased rent in their own profit margins. The competitive market, being what it is, will mean that most likely that A and B will be unable to increase their prices. As such, they must achieve some operational savings elsewhere.

41. So why would A and B decide to end their relationship? It must be that whatever overhead losses they incur from the split will be more than offset by other savings that each of them will achieve. In other words, private gains from a divestiture will motivate such a move despite the possible loss of savings due to common overhead expenses. CPC and EDTI chose to part ways for a variety of reasons that surely must make sense to the EPCOR organization as a whole. If, as in the competitive marketplace, it made financial and operational sense to split, then surely, as in the competitive marketplace, it would make sense that EDTI cannot pass on all of the lost savings to customers.

42. This, of course, runs counter to EDTI's symmetry principle. It may also run counter to the "stand-alone" principle depending on how that principle is applied. The "underpinning of the stand-alone principle is that the regulated utility should not be subsidizing its non-utility operations or operations of members of its corporate family, neither should the non-regulated activities subsidize the utility operations."[12] The asymmetric treatment of a utility in this situation, therefore, creates a "shield-sword" dichotomy, a dichotomy not unknown to those practicing the common law and regulatory law alike.[13]

43. For example, in *AltaLink Management Ltd.*, AltaLink sought to have the Alberta Energy and Utilities Board (board or EUB) calculate an income tax allowance commensurate with a taxable entity.[14] The City of Calgary objected and argued it was inappropriate to raise the just and reasonable rate of return under the stand-alone principle,[15] because the stand-alone principle was developed to shield customers from absorbing the cost of funds resulting from decisions of consolidated entities.[16] The board took a middle ground approach and decided to establish a tax allowance by looking at the tax status of AltaLink's partners. The board stated "that in a cost of

[12] Decision 2003-061: AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariff for May 1, 2002 – April 30, 2004, TransAlta Utilities Corporation Transmission Tariff for January 1, 2002 – April 30, 2002, Application Nos. 1279345, 1279347, and 1287507, August 3, 2003

[13] In other areas of the law, the idea that certain doctrines can be used as a shield and not a sword, i.e. an asymmetrical usage of a doctrine, is not new. Promissory estoppel, privity of contract, acquiescence, the statute of frauds, and so many more areas of the law too numerous to justly enumerate in this footnote, are but a few examples where the doctrine allows one party to use the doctrine as a shield against another's claims but not establish the claims in the first place.

[14] AltaLink Management Ltd. and TransAlta Utilities Corporation, Decision 2003-061, page 78.

[15] Ibid, at page 79.

[16] Ibid.

service jurisdiction where revenue and costs are forecast on a prospective basis, a cost is recoverable in customer rates if there is a reasonable expectation that it will be incurred."[17] Prior to the hearing, interestingly, one of the partners had a tax free status but later changed it. The board, however, made no allowance for that partner since there was "no such expectation with respect to income taxes when the partner is initially structured as non-taxable and later inexplicably changes its tax status with the result that customers are expected to provide it with an income tax allowance."[18]

44. The courts have always affirmed the flexibility of the Commission to examine the corporate structure of utilities and its parent organization with respect to setting rates. In *ATCO Electric Ltd. v. Alberta (Energy & Utilities Board)*,[19] the Court of Appeal held that the EUB "ha[d] the jurisdiction to segregate business functions of an integrated utility – and determine a notional corporate organizational model – for purposes of evaluating risk and calculating prudent carrying costs associated therewith."[20] The Court approved of the board's actions which were in line with evidence of independent financial experts, and noted with approval that the board followed the advice of the experts that:

> … the Board should "not apply the stand-alone principle by rote. Instead the Board should deal with the reality, utilize independence of thought, question assumptions and think through whether an approach that has been applied in the past in different circumstances should be applied now in new circumstances. Such an approach should lead the Board to deal with reality and decline to apply the stand-alone principle to the detriment of the customers of the [distribution companies].[21]

45. EDTI advanced another principle to bolster its argument for the symmetry principle. It argued that to treat the corporate costs asymmetrically would create a perverse incentive for EDTI, or any other similarly situated utilities. If a utility was expected to pass its economies of scale and scope savings onto customers but not allowed to recoup any losses from them, then this would remove any incentive by the utility to seek out those economies in the first place. This argument has some merit, and it is no surprise, therefore, that the current focus of the Commission for the next few years is the design of efficiency-seeking incentives for all utilities. The UCA did not advance a good response to this argument other than to seek out an audit of the costs. In our view, this principle is a better principle than a pure symmetry principle. This symmetry plus incentive principle at least provides the Commission, or at least these two concurring Commission Members, some comfort in knowing that the interests of customers are also being considered.

46. Whether a utility would require a full symmetric treatment of corporate costs in order to motivate it to achieve efficiencies or whether some partial recovery would be enough is an open-ended question that we expect EDTI could pursue in the future. Similarly, we expect the interveners to turn their mind to this principle as well as the asymmetric principle, or the "shield-sword" principle as we called it.

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[17] Ibid, at page 84.
[18] Ibid.
[19] ATCO Electric Ltd. v. Alberta (Energy & Utilities Board), 2004 ABCA 215.
[20] Ibid. at paragraph 181.
[21] Ibid, at paragraphs 178-181.

TAB 8

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0744

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B)

AND IN THE MATTER OF an application by Great Lakes Power Limited for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective September 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Bill Rupert
Member

Cathy Spoel
Member

DECISION AND ORDER

THE APPLICATION

Great Lakes Power Limited ("GLPL", the "Applicant" or the "Company") filed an application under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15 (Schedule B) with the Ontario Energy Board (the "Board"), received on August 31, 2007, seeking approval for changes to the rates that GLPL charges for electricity distribution, to be made effective September 1, 2007. In addition, GLPL requested the Board to make the current distribution rates interim as of September 1, 2007 and to authorize the establishment of a deferral account to record revenue requirement deficiencies incurred from September 1, 2007 until new distribution rates are implemented.

Mitigation for Seasonal Customers

RRRP payments are not available for GLPL's non-residential customer classes, being Seasonal and Street Lighting. For those customers, GLPL proposed to hold total bill impacts to no more than 10%.

For the Seasonal customer class, the total bill impact was forecast to be an increase of 51% prior to mitigation[24]. GLPL requested a deferral account to record the revenue shortfall of approximately $1,011,800 per year that resulted from limiting the impact. The bill impact on Street Lighting is forecast at approximately 25% prior to mitigation. GLPL did not propose to record or recover the shortfall that will be the result of mitigation for this class.

VECC agreed with the proposal to mitigate the impact on Seasonal customers but was concerned that future recovery may fall to other customer classes.

Board findings

The Board accepts the Applicant's proposal to establish a mitigation plan for Seasonal customers and to reflect in a deferral account the amount of revenue foregone arising from that mitigation plan. The Applicant will use account 1574.

The Board is concerned however, that this deferral account not be permitted to accumulate a balance that at some point may produce even more undesirable outcomes than the rate increases it is designed to avoid.

In its next rate application the Applicant is required to present a planned approach for the management of the mitigation plan so as to ensure that balances are cleared with regularity, at levels and in a manner that does not result in undue hardship for these customers or any other class of customers.

2007 TEST YEAR INCOME TAX

GLPL's income taxes for regulatory purposes for 2005 through 2007 are shown in Table 7.

[24] GLPL Argument-in-Chief, p. 36

Table 7: Regulatory Income Taxes

	2005 Actual	2006 Actual	2007 Forecast
Federal	$ 172,000	$ 77,600	$ 949,500
Provincial	113,400	35,600	623,700
Total	**$ 285,400**	**$ 113,100**	**$ 1,573,200**

Source: GLPL Argument-In-Chief, p. 22.

The amounts shown in Table 7 differ from the amounts included in GLPL's pre-filed evidence for two reasons. Firstly, the amount of tax for 2007 has increased by a minor amount due to an adjustment in capital cost allowance (CCA) claims. Secondly, at the Technical Conference, GLPL amended its 2005 and 2006 tax calculations to include in taxable income the amounts that GLPL booked to the rate mitigation sub account of deferral account 1574 in those years. That amendment resulted in regulatory tax expenses in those years compared to the tax losses shown in the pre-filed evidence. GLPL stated that there is no tax loss carry-forward created by the Distribution business on a stand-alone basis.

As a corporation, GLPL is obliged to pay federal and provincial income taxes. Its taxable income or loss is calculated on the aggregate income or loss of all of its businesses. The financial results of GLPL's distribution business are included in the calculation of the corporation's taxable income although the distribution business does not file tax returns because it is a division of GLPL rather than a separate legal entity.

VECC submitted that it is unclear whether the proposed 2007 tax provision takes into account new CCA classes and rates that were introduced in the March 2007 federal budget. In its reply, GLPL agreed to incorporate the new classes and rates in the tax calculation when it prepares a draft rate order. The Board finds this approach acceptable.

Board staff questioned the need for an income tax provision in the 2007 revenue requirement in light of GLPL's pre-2007 corporate tax loss carry-forwards. GLPL stated that those loss carry-forwards arose because of expenses in the company's non-distribution businesses. Staff also took the position that, in the event the Board disallows recovery of a deferral account balance, the regulated distribution business itself would have pre-2007 losses that should be used to eliminate any 2007 tax provision. Both of these issues are addressed in the sections below.

Benefit of tax losses arising from GLPL's unregulated businesses

At the end of 2006, GLPL had material tax losses that can be carried forward to offset future taxable income. GLPL stated that those losses were due to expenses of its non-distribution businesses and should be disregarded in setting the revenue requirement of the regulated distribution business. GLPL submitted that this approach was consistent with the stand-alone principle for income tax provisions that has been adopted by the Board and other regulators.

Board staff expressed concerns about GLPL's proposal to include an income tax provision in its 2007 revenue requirement notwithstanding the fact that GLPL has tax loss carry-forwards that would eliminate the corporation's 2007 tax bill. The staff submission stated: "Parties may wish to comment on the stand-alone concept in this case with respect to 2007 test year tax allowance. Stated more directly, should the ratepayers pay for federal and provincial taxes that will not be paid?"

In its reply submission, GLPL argued that:

> *Board staff is effectively requesting that the Board depart from its long established application of the stand alone principle applied in respect of the provision of regulatory tax allowances and to adopt the concept that regulatory tax allowance[s] should reflect an apportioning of tax payable between the distribution and non-distribution business.*

GLPL provided several excerpts from past Board decisions and other sources to support its claim that the stand alone principle has been adopted for income tax provisions by the Board and other regulators, and to illustrate how the principle has been applied in proceedings before the Board and in other jurisdictions. GLPL submitted that were the Board to abandon the stand alone principle in this case, the resulting rates would not be just and reasonable because:

- Ratepayers would receive the benefit of a tax deduction without paying the expense which gave rise to it;

- Cross subsidization would occur because rates would be based on a tax expense that would be lower than it would have been absent the non-distribution businesses;
- There would be retroactive altering of the conditions assumed by the investor at the time investments were made in the non-utility operations; and
- Shareholders of GLPL would be denied the same treatment available to other shareholders under the *Income Tax Act*.

Board Findings

The Board finds that the 2007 test year tax provision should be calculated without regard for corporate tax loss carry-forwards that arose due to losses in GLPL's non-distribution businesses.

The Board agrees with GLPL that it has been the Board's policy to apply the stand-alone principle when assessing the tax provisions of regulated businesses. In the Board's view, fairness in ratemaking requires adherence to the principle that a party who bears a cost should be entitled to any related tax savings or benefits.

Prior to release of the *2006 Electricity Distribution Rate Handbook* ("2006 DRH"), the Board considered arguments related to a somewhat similar question – Who should benefit from the tax deductions for expenses that are not included in the determination of a distributor's rates? The Report of the Board on the Handbook states that:

> *… the Board rejects the proposal by Schools, and concludes that tax savings arising from disallowed expenses, including purchased goodwill and charitable donations, will not be allocated to ratepayers. Ratepayers have not paid for the expense through rates, and therefore are not entitled to the tax benefit.*[25]

The principle that the Board relied on in accepting the 2006 DRH treatment of disallowed expenses is equally applicable in this case. The pre-2007 expenses and losses of GLPL's unregulated businesses were borne by GLPL's shareholder, not ratepayers. It would be fundamentally unfair to take such tax losses into account when

[25] RP-2004-0188, May 11, 2005, p. 55.

setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

Benefit of pre-2007 tax losses in GLPL's regulated business

As noted earlier, GLPL's evidence is that there are no pre-2007 loss carry forwards in the distribution business on a stand-alone basis. The reason for that result appears to be that, in years before 2007, GLPL included in its calculation of taxable income the annual increase in deferral account 1574. Board staff submitted that "if the values accumulated in account 1574 are not permitted for recovery in rates, it appears the GLPL distribution division would have incurred operating losses in years prior to the test year." In the staff's opinion, the existence of such prior year regulatory tax losses would make it unnecessary for a tax allowance to be recovered from customers in 2007. [26]

The second tax issue raised by staff is whether, in the event the Board disallows recovery of a deferral account balance, the regulated distribution business itself would have pre-2007 losses that should be used to eliminate any 2007 tax provision.

GLPL argued that, in the event the Board disallows recovery of the balance in account 1574, loss carry-forwards arising pre-2007 should be for the benefit of GLPL's shareholder. GLPL noted that any pre-2007 losses that arise in the event of the Board's denial of recovery of account 1574 must be due to variations in load or expenses compared to the amounts on which GLPL's then existing rates were based. Ratepayers would not have paid any amount due to unfavourable variations in load or expenses. Based on the stand-alone principle, GLPL argued that ratepayers should not be entitled to any benefit of those losses and that applying such pre-2007 losses to reduce the 2007 regulatory tax provision would constitute retroactive ratemaking. Board staff did not comment in its submission on whether the reason for the pre-2007 losses is relevant to whether the losses should be used to eliminate 2007 taxes.

[26] In its submission, Board staff also argued that GLPL has overstated its regulatory tax provisions in 2006 and earlier years by voluntarily including the annual increase in account 1574 in taxable income. Staff submitted that GLPL's action of recognizing the increase in account 1574 as taxable income in 2006 and earlier years is not something a stand-alone business would consider necessary or would consider to be prudent tax management. In effect, the staff seemed to be arguing that GLPL should be considered to have loss carry-forwards for regulatory purposes whether or not the Board disallows recovery of account 1574. Because the Board has determined that GLPL will not be permitted to recover the balance in account 1574, it is not necessary to consider and make a finding on this alternative staff argument.

Board Findings

Given that GLPL has included the annual accruals to account 1574 in its taxable income for 2006 and earlier years, the Board's decision to disallow recovery, as set out earlier in this decision, will affect GLPL's tax returns. Board staff and, it appears, GLPL as well, assume that a Board decision to disallow recovery would require GLPL to file revised tax returns for 2006 and earlier years that exclude the account 1574 accruals. That would result in a higher pre-2007 loss carry-forward than has been reported by GLPL to date. The Board has accepted that assumption in its analysis and findings on this issue. However, whether that is the required tax treatment, or whether the earlier tax returns will be left unchanged and the disallowance deducted in 2007 or 2008 tax returns as a loss, would have no effect on the Board's findings on this issue.

The 2006 DRH sets out for electricity distributors how the Board generally intended to address applications for 2006 distribution rates. Among other issues, it dealt with how loss carry-forwards would be treated in setting the 2006 revenue requirements of distributors. The DRH sets out the consensus view of the working group as to how loss carry-forwards should be treated:

> *A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, apply them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation.*[27]

The Report of the Board that accompanied the 2006 DRH discussed the Board's rationale for approving this treatment of loss carry forwards:

> *The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.*
>
> *Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.*

[27] 2006 Electricity Distribution Handbook, May 11, 2005, p. 61.

> *Conclusions*
>
> *The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for reasons that may be related to ratepayers. The Board notes that the consensus approach [take loss carry-forwards into account when setting 2006 rates] will reduce the variance between taxes collected in rates and actual taxes paid. The Board will accept this approach in the Handbook.*[28] *[emphasis added]*

Although the Board accepted the position in the 2006 DRH that loss carry-forwards should be taken into account in setting 2006 rates, the Board does not believe that position is applicable in all rates cases before the Board. It is clear from the highlighted sentence in the Report of the Board that the Board attaches some significance to the reasons for losses. It is also clear from that sentence that approval of the 2006 DRH position on loss carry-forwards was taken without the opportunity to hear any evidence on what might have led to the losses.

The balance in account 1574 as at December 31, 2006 was over $12 million. That amount is more than 50% of the capital account (owner's equity) shown in GLPL's 2006 audited financial statements. Since the Board has denied recovery of a major portion of account 1574, the amount denied would be excluded from GLPL's pre-2007 financial results thereby indicating that GLPL would have incurred significant operating losses for the period 2002 to 2006. It is highly unlikely, in the Board's view, that GLPL's customers absorbed any of those losses. Except for some increases in rates authorized by the Board to collect certain regulatory assets, GLPL's distribution rates have not increased since May 2002, when GLPL's rates first became subject to Board oversight. In fact, in June 2003, the Minister of Energy directed the Board to reduce rates for GLPL's residential and certain other customers.

The Board finds that pre-2007 losses of the distribution business should not be used to eliminate the tax provision for the 2007 test period. The Board reiterates its view that the benefits of a tax loss should be realized by the party – shareholders or ratepayers – that bore the expenses or losses that gave rise to the tax loss. Since the Board has denied recovery of the amount accrued for rate mitigation in account 1574, the resulting

[28] RP-2004-0188, Report of the Board, May 11, 2005, p. 57.

losses should not be attributed to ratepayers but rather to GLPL, which sustained those losses and should retain the related tax benefits.

DEFERRAL AND VARIANCE ACCOUNTS

In addition to account 1574, Deferred Rate Impact Amounts, which has been discussed earlier in this Decision, the Company proposed to dispose of balances in certain deferral/variance accounts and to establish two new accounts.

Existing Deferral and Variance Accounts

The following additional accounts were requested for clearance as per GLPL's Argument-in-Chief:

1508 Other Regulatory Assets $207,609
1562 Deferred Payments In Lieu of Taxes ($103,338)
1570 Qualifying Transition Costs $1,103,217
1580 RSVA – Wholesale Market Service Charge $211,882
1584 RSVA – Retail Transmission Network Charge $(2,893)
1586 RSVA – Retail Transmission Connection Charge ($298,501)
1588 RSVA – Power $179,341
1590 Recovery of Regulatory Balances ($3,057,670)

1508 Other Regulatory Assets

GLPL has requested recovery of account 1508 sub-account OEB Cost Assessments. This balance is related to the difference between OEB cost assessments for 2004/05 and 2005/06 up to April 30, 2006 and the amount of OEB costs included in GLPL's current rates.

Intervenors had no comments on this balance.

Board Findings

The Board approves disposal of the balance in Account 1508 in the manner described in the section, Implementation of Clearance of Deferral and Variance Accounts, later in this decision.

TAB 9

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2009-0408

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP seeking changes to the uniform provincial transmission rates for 2010.

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Ken Quesnelle
Member

DECISION WITH REASONS

July 21, 2010

INTRODUCTION

THE APPLICATION

Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP (“GLPT” or the “Applicant”) filed an Application with the Ontario Energy Board (the “Board”) on November 30, 2009 under section 78 of the *Ontario Energy Board Act, 1998*, 1998 S.O. c.15, (Schedule B). GLPT sought approval for changes to the Uniform Transmission Rates (UTR) that GLPT and other transmitters charge for electricity transmission, to be effective January 1, 2010. The Board assigned Board file number EB-2009-0408 to the Rate Application.

GLPT also filed an application with the Board on November 27, 2009 requesting that a deferral account be granted for the purposes of recording capital expenditures as well as operation, maintenance and administration expenses related to renewable generation connection, system planning, and infrastructure investment arising from the *Green Energy and Green Economy Act , 2009* (the “Deferral Account Application”). The Board assigned Board file number EB-2009-0409 to the Deferral Account Application.

The Board issued a Notice of Applications and Combined Hearing dated December 31, 2009 for both applications, and directed GLPT to commence service and publication of the Notice on Monday, January 4, 2010. A decision on the Deferral Account Application was issued on March 25, 2010.

THE PROCEEDING

On January 29, 2010 the Board issued Procedural Order No. 1 and Interim Rate Decision, which included a schedule for procedural steps for the rate application (the “Procedural Schedule”) and determined that the current Uniform Transmission Rates as they relate to GLPT would be made interim as of January 1, 2010. The Board’s approval of the settlement agreement filed in this proceeding renders the new rates effective January 1, 2010.

In Procedural Order No.1 the Board granted intervenor status to Energy Probe Research Foundation (“Energy Probe”), the Vulnerable Energy Consumers Coalition (“VECC”), Canadian Niagara Power Inc. (“CNPI”) and the Independent Electricity System Operator.

The Board subsequently granted late requests for intervenor status to the School Energy Coalition (“SEC”) and Hydro One.

According to the Procedural Schedule, the applicant filed its interrogatory responses on March 3, 2010 accompanied by a request for confidential treatment of certain information included in GLPT’s response to two Board staff interrogatories (the “Requested Confidential Information”). The Board subsequently issued a Decision and Order on March 31, 2010, in which it ordered that the Requested Confidential Information would remain confidential.

On March 18, 2010 the Board issued Procedural Order No. 3 to allow parties an opportunity to file supplemental interrogatories to address responses which were unclear or which required further explanation. The Board also made provision for a technical conference, to be held on April 14, 2010.

On April 9, 2010 GLPT filed responses to the supplemental interrogatories and requested confidential treatment for some of the information. On April 30, 2010 the Board issued a Decision and Order on Confidentiality of Additional Information and Procedural Order No. 6 in which it ordered that the additional information would remain confidential.

On May 3, 2010 GLPT and three intervenors, SEC, VECC and Energy Probe participated in a Settlement Conference with the assistance of a facilitator. As a result of the Settlement Conference, the parties prepared a Settlement Proposal and agreed to present it to the Board.

THE SETTLEMENT AGREEMENT

GLPT’s original application included a revenue requirement of $38,915,026. The Proposed Settlement Agreement sets the revenue requirement at $35,148,818. The reduction is largely based on reductions in projected OM&A costs and adjustments to the calculation of capital cost allowance.

In the Decision and Order Proposed Settlement Agreement (the “Settlement Decision”) issued May 21, 2010, the Board accepted the Proposed Settlement Agreement, as submitted (the “Accepted Settlement Agreement”). The Accepted Settlement Agreement is attached as Appendix “A” to this Decision.

The Board made one caveat in its Settlement Decision in respect of section 3.1 of the Accepted Settlement Agreement dealing with Operations, Maintenance & Administration (“OM&A”) for future GLPT applications.[1] The Accepted Settlement Agreement is binding on the parties to the agreement, but it cannot fetter the discretion of another Board panel considering a future application by GLPT.

The Board confirmed that the Accepted Settlement Agreement covers all aspects related to the Board approved revenue requirement for year 2010, except for one unsettled issue. The Board recognizes the parties’ agreement that the Accepted Settlement Agreement shall not be affected by the Board's determination in regard to the one unsettled issue.

THE TAX ALLOWANCE

THE UNSETTLED ISSUE

The unsettled issue relates to the question of whether GLPT is entitled to recover an income tax allowance in the amount of $1,729,806 for the 2010 Test Year.

Parties took issue with the request to recover the tax allowance for a number of reasons and argued that the tax allowance should either be denied or reduced as a result of some of the following arguments, summarized here in brief:

(a) that the “stand alone” principle had been misapplied by the applicant;
(b) that the income tax allowance was not being used to pay for costs incurred by the applicant;

[1] Decision and Order Proposed Settlement Agreement, p.3

(c) that the corporate structure beyond the taxable partners is relevant to whether a tax allowance should be granted;

(d) that the benefit is created by two entities coming together therefore akin to an affiliate transaction; and

(e) that a decision in favour of the applicant in this case would result in more aggressive tax planning in the regulatory sector.

The submissions of SEC, VECC, and Board Staff are addressed below in the Board's findings which follow.

THE SEC MOTION

On May 12, 2010, SEC filed with the Board on a confidential basis a Notice of Motion and Motion Record seeking orders that:

(a) the Applicants be compelled to provide a full answer to questions on pages 58 and 66 of the Technical Conference held April 14, 2010;

(b) the Applicants be compelled to file the documents requested in SEC Interrogatory #1 and SEC Supplementary Interrogatory #3; and

(c) such further and other relief as the counsel for SEC may advise and this Board may permit.

In Procedural Order 7, dated May 17, 2010, the Board determined that it would treat all materials in relation to the motion as confidential on an interim basis. Factums were filed in confidence by SEC, VECC, Board staff, and GLPT.

The motion was heard orally on Thursday, May 27, 2010, and the proceeding was conducted *in camera*. The parties filed proposed redactions to the various motion materials during the proceeding and filed proposed redactions to the motion day transcript on May 28, 2010. The Board accepted the proposed redactions and a redacted version of the transcript has been placed on the public record.

The Board issued its Motion Decision and Order on May 28, 2010. The Board concluded that the requested information is irrelevant to its consideration of the tax allowance issue and indicated that it would not order production of the requested information. Additional issues were raised during the motion proceeding. SEC raised the following questions:

- whether a tax loss arising from tax deductions should be treated in the same way as a tax loss arising from an operating loss;
- whether the tax situation is akin to an affiliate transaction and therefore whether a sharing of the tax benefits arising would be appropriate; and
- whether a case involving different divisions within a single corporate entity is an appropriate analogy to the partnership arrangement in this case.

The Board made no determination on those matters in the Motion Decision and Order, and indicated that SEC may wish to pursue these aspects of the tax provision issue along with other aspects in the hearing on the unsettled issue.

The Motion Decision and Order set out remaining dates for the proceeding to address the unsettled issue.

The oral hearing on the unsettled issue was held on June 3, 2010. GLPT filed a confidential version of its argument-in-chief as well as a redacted version on June 8, 2010. Board Staff filed its confidential submission on June 15, 2010 and a redacted version was filed on the public record on June 22, 2010. SEC filed its confidential final argument on June 15, 2010, which later was accepted by the applicant without redaction for the public record. GLPT filed its non-confidential reply on June 21, 2010.

CORPORATE STRUCTURE

The two partners that form the GLPT limited partnership are the general partner, GLPT Inc. with a 0.01% interest, and the limited partner, Brookfield Infrastructure Holdings (Canada) Inc. ("BIH"), with a 99.99% interest.[2] GLPT Inc. is a wholly owned subsidiary of BIH.[3] BIH is ultimately owned 60% by Brookfield Infrastructure Partners L.P.[4], a Bermuda based limited partnership[5], and 40% by Brookfield Asset Management Inc.[6]

[2] GLPT LP Factum May 25, 2010 page 2, paragraph 5
[3] Exhibit 4, Tab 3, Schedule 2, page 2, lines 11-12
[4] Transcript, June 3, 2010, page 51, lines 6-8
[5] GLPT's response to Board staff supplementary interrogatory 15 (i), where the web page was provided as follows: http://www.brookfieldinfrastructure.com/ir_tax.html

The partners of GLPT report their proportionate shares of taxable partnership income from GLPT and file tax returns as corporations with the Canada Revenue Agency, which also administers Ontario corporate tax on behalf of the province.

CONFIDENTIALITY

Throughout the proceeding there have been a number of requests to keep certain material confidential. The business sensitivity of some of the information requested in this proceeding by Board staff and intervenors could convey what might be considered forward-looking statements affecting the valuation of publicly traded companies. As such, the applicant agreed with parties on a set of assumptions on which arguments could be premised such that arguments on the unsettled issue could be placed on the public record.

GLPT acknowledged that BIH's taxable income for 2009 was reduced to nil because the losses in Island Timberlands were sufficient to offset GLPT's income in 2009. Documents on the record of this proceeding and previously filed with the Securities and Exchange Commission in the U.S. confirm these facts for the purposes of the public record.[7]

The applicant further agreed that the submissions of each of the parties could be premised on any of the following assumptions:

(a) that there will be sufficient losses to offset the net income arising from GLPT in 2010 and that these losses will arise from current year losses;
(b) that there will be sufficient losses to offset the net income arising from GLPT in 2010 and that these losses will arise from loss carry forwards; or
(c) a combination of (a) and (b).

Evidence which remains confidential includes: tax return information for the two corporations (GLPT Inc. and BIH Inc.), certain charge determinant data for large customers, and the tax positions of the limited partners of GLPT for 2010.

[6] Exhibit 1, Tab 1, Schedule 12, Page 5 of 6
[7] SEC Redacted Motion Record, Tab 6, Copy of Form 20-F/A for 2009

Using a hypothetical situation and making assumptions in argument for purposes of the test year reduced the need to file arguments in confidence or to make significant redactions, and this approach has assisted this Board in providing a meaningful decision for the public record.

BOARD FINDINGS

The core of the unsettled tax allowance issue is whether and how the "stand alone" principle should be applied in this case. The stand alone principle, in the context of taxes, has been described by the Board as follows:

> In the Board's view, fairness in ratemaking requires adherence to the principle that a party who bears a cost should be entitled to any related tax savings or benefits.[8]

For the reasons set out below, the Board finds that the stand alone principle is applicable in this case and that the tax allowance arising from the settlement agreement ($1,729,806) will be allowed in rates.

SEC, Board staff, and VECC raised three main arguments in their submissions:

1. The tax allowance is not a real cost.
2. The arrangement is a type of affiliate transaction and therefore ratepayers are entitled to a share of the net benefit arising from the transaction.
3. Approving inclusion of the tax allowance in rates will encourage other utilities to undertake aggressive tax planning which will reduce the focus on utility operations and will reduce the PILs revenue for the province.

We will address each of these arguments.

1. The tax allowance is not a real cost

It has been assumed by the parties, for purposes of argument, that in 2010 current and/or past tax losses in Timberlands will offset the taxable income derived from GLPT for the test year. The intervenors submitted that if the tax is not actually paid to the tax

[8] *Great Lakes Power Limited*, EB-2007-0744, Decision and Order, October 30, 2008, p. 40.

authorities in the test year (or at some future date which is known with some certainty), then it is not a real cost and should not be recovered in rates.

SEC asserted that the stand alone principle was developed in the United States in the context of a standard corporate structure and the associated consolidated tax filing permitted in the United States. SEC further asserted that Canadian tax provisions are more restrictive and, by implication, the stand alone principle may not be applicable to the GLPT situation. In SEC's view, recent case law supports its view that movement away from a standard corporate structure tests the limits of the stand alone principle.

GLPT took the position that the GLPT tax allowance is a real cost: "The income from GLPT has the effect of reducing tax losses that would otherwise be available in the future to offset taxable income arising from Timberlands. A tax liability is incurred."[9]

The Board agrees with GLPT that a tax liability exists and that a tax liability is a real cost which is eligible for recovery. The evidence is clear that the net income earned by GLPT is taxable. This tax liability is derived from the regulated activities of the regulated business GLPT.

Tax losses or deductions from outside the regulated business may result in no tax being paid by a particular entity (depending upon the corporate structure), but that does not mean the tax liability is not a real cost to the regulated business. The benefit of the tax losses arise from expenditures which remain outside the regulated business. Ratepayers have not borne those expenses, and therefore are not entitled to the benefits arising. The Board has addressed this issue in a number of different circumstances in the past. The most recent case involved Great Lakes Power Limited ("GLPL"), a predecessor company to GLPT, and the treatment of tax losses arising from the unregulated business of a different division within the same corporation. In that decision, the Board stated:

> The pre-2007 expenses and losses of GLPL's unregulated businesses were borne by GLPL's shareholder, not ratepayers. It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To

[9] GLPT, Reply Argument, p. 2.

> abandon the stand alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.[10]

Board staff submitted that the prior GLPL case was not applicable because "companies in the electricity sector are no longer permitted to operate under a divisional model."[11] Board staff further submitted that:

> the Board should exercise caution in applying the stand alone principle in this case in the way it did in the GLPL distribution case as it could result in sanctioning a structure that could be a *de facto* divisional organization and no longer permitted.[12]

Although the divisional model is no longer permitted, the analysis in the GLPL case may still be applicable. The legality of the current corporate structure is not an issue before the Board in this proceeding. There has been no evidence that GLPT is operating in contravention of section 71 of the *Ontario Energy Board Act, 1998*. The Board could and would examine such an allegation directly should it be appropriate to do so. The Board will proceed in this case on the assumption that the structure is in accordance with legislated requirements and therefore finds that the analysis in the GLPL is applicable in the current circumstances. Board staff appears to be concerned that allowing the tax provision would in some way sanction a structure which was not otherwise permitted. The Board is satisfied that a decision in this proceeding to permit a tax allowance would not validate a corporate structure if the structure were in fact in contravention of section 71.

The Board further notes that while the GLPL case addressed the situation of a division, this was but one application of the stand alone principle. The principle has been upheld by the Board in other circumstances as well. These proceedings include the 2006 Electricity Distribution Rate Handbook, the Filing Guidelines for March 1, 2002 Distribution Rate Adjustments, Natural Resource Gas Limited (EBRO 496, August 20, 1998), and Consumers Gas (EBRO 376 I and II, January 30, 1981), among others.

[10] *Great Lakes Power Limited*, EB-2007-0744, Decision and Order, October 30, 2008, p. 40.
[11] Board staff, Argument, p. 7.
[12] Board staff, Argument, p. 8.

As a related argument, Board staff suggested that the Board may wish to look further into the corporate structure beyond the partners of GLPT. The Board does not agree. The two partners are taxable corporations in Canada. There is therefore no reason to look further up the Brookfield corporate structure for purposes of determining the tax position.

2. The arrangement is a type of affiliate transaction and therefore ratepayers are entitled to a share of the net benefit arising from the transaction.

SEC submitted that the tax arrangements are in effect a transaction which serves to provide a benefit which neither entity (Timberland and GLPT) can produce individually. For Timberlands, the losses have no current value, only potential future value. It gets present value from its losses through "co-operation" with GLPT. GLPT gets a present benefit by reducing its taxes in co-operation with Timberlands. SEC concluded that the net benefit of $1.7 million (the tax allowance) should be shared 50% with ratepayers. VECC took essentially the same position and made the same recommendation that the net benefit be shared 50% with ratepayers. Board staff also suggested that there be a sharing of the benefit created by Timberlands and GLPT coming together for tax purposes.

GLPT maintained that there was no affiliate transaction involved because the two businesses operate separately and there is no sharing of resources, costs, revenues or management. In GLPL's view:

> Under the *Income Tax Act*, the requirement for BIH Inc. to file a single tax return accounting for the net income or losses from all partnerships in which it is a partner gives rise to the netting of taxable income and tax losses. This is the product of the tax rules applying and not any actual transaction between two separate and independent businesses.[13]

The Board finds that the tax situation is not in the nature of an affiliate transaction, or a sharing of corporate services. There is evidence on the record that there is some type of market for tax losses, but this is not determinative of whether the tax situation for GLPT represents an affiliate transaction. The Board finds that the actions taken by GLPT and the partners, which flow from the operation of the *Income Tax Act*, cannot be said to

[13] GLPT, Reply Argument, p. 17.

amount to a transaction. Further, the Board agrees with GLPT that the benefit which arises is the tax loss which can be applied against the tax liability. This benefit arises from expenses which are borne not by ratepayers, but by the unregulated business. The Board does not agree that the benefit is created by the entities coming together; the benefit is the tax loss for BIH, which may be used in the present or in the future, depending upon the circumstances, and that arises solely from the expenses of the unregulated business.

3. Approving inclusion of the tax allowance in rates will encourage other utilities to undertake aggressive tax planning which will reduce the focus on utility operations and will reduce the PILs revenue for the province.

SEC submitted that if the Board approved the tax allowance in rates, then the effect could be to encourage “aggressive tax planning” by utilities. In SEC’s view this would create two problems: a reduced focus on utility operations and reduced tax intake for Ontario. Board staff also expressed concern about potential tax leakage.

The Board finds that it would not be appropriate to address either of these two issues by denying the inclusion of a tax allowance in rates. Presumably the objective of such an approach would be to provide a disincentive to certain corporate structures. However, such an approach would be indirect at best.

With respect to potential diversion of resources from utility operations to aggressive tax planning, the Board finds that it would be appropriate to address such concerns directly. If there were evidence that a particular structure, or activity, was leading to adverse operating or financial conditions for ratepayers, then the Board would address that directly through licence conditions, or other regulatory instruments. There is no such evidence in the current proceeding.

With respect to potential adverse consequences from a provincial or other tax revenue perspective, the Board concludes that if there are adverse tax implications from an otherwise lawful arrangement, then it is for the tax authorities to address the situation directly through the tax rules.

IMPLEMENTATION

The Board notes that GLPT has a significant balance, approximately $2.5 million, owing to ratepayers in account 1574, Deferred Rate Impact Amounts Account ("DRIAA"). GLPT could use this account to fully offset the increase to its revenue requirement for 2010, resultant of this Decision, without necessitating changes to existing UTRs.

The Board sees benefit to minimizing the number of changes to UTRs where it is appropriate to do so. If GLPT is capable of making the necessary entries to the DRIAA account without necessitating changes to the existing UTRs[14] at this time, the Board would encourage such a proposal. There are currently two other transmission rate applications before the Board, which provide opportunities to more appropriately align and reflect GLPT's 2010 Board approved transmission revenue requirement and charge determinants in the near future.

The Board directs GLPT to file its implementation proposal with the Board and all intervenors. GLPT shall file its implementation proposal within 10 calendar days of the issuance of this Decision. Intervenors shall have 10 calendar days to respond to GLPT's implementation proposal. GLPT should respond as soon as possible to any comments by intervenors, but not later than 7 calendar days after the deadline for comments from intervenors.

If GLPT cannot file an implementation proposal as above, GLPT shall file a draft rate order including the Ontario Transmission Rate Schedules and Revenue Allocators and file a separate exhibit showing clearly the calculation of the uniform transmission rates and revenue allocators. GLPT should provide a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits. Such process, if necessary, will be governed by the timelines set out above for the implementation proposal.

COST AWARDS

[14] EB-2008-0272. Order issued January 21, 2010 in Hydro One Networks Inc. set Uniform Transmission Rates effective January 1, 2010.

Of the parties granted intervenor status, VECC, Energy Probe, and SEC requested eligibility to seek an award of costs for participation in this proceeding; the requests were granted.

The Board indicated in its March 25, 2010 Deferral Account Application decision (Board File EB-2009-0409) that cost claims with respect to that proceeding would be addressed in this proceeding.

Parties eligible for costs shall submit their claims on or before Wednesday, August 11, 2010. The cost claim must be filed with the Board and one copy is to be served on GLPT. The cost claims must conform to the Board's practice Direction on Cost Awards.

GLPT should review the cost claims. Objections must be filed with the Board and one copy must be served on the party against whose claim the objection is made, by Wednesday August 18, 2010.

The party whose cost claim was objected to will have until Wednesday August 25, 2010 to respond. Again, a copy of the submission must be filed with the Board and one copy is to be served on GLPT.

GLPT shall pay the Board's costs upon receipt of the Board's invoice.

DATED at Toronto on July 21, 2010
ONTARIO ENERGY BOARD

Original signed by

____
Cynthia Chaplin
Vice Chair and Presiding Member

Original signed by

____
Ken Quesnelle
Member

TAB 10

Ontario Energy Board

Commission de l'Énergie de l'Ontario

RP-2004-0188

2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

REPORT OF THE BOARD

2005 MAY 11

BACKGROUND

The 2006 Electricity Distribution Rates consultative involved several phases. The project was initiated by a letter from the Board to all distributors and other stakeholders dated June 16, 2004. In July 2004, Board staff met with stakeholders to discuss potential issues to be addressed in the process. The Board published a notice in the media inviting public participation and comment. A further issues meeting was held in September, and working groups were formed to begin drafting a rate handbook. The progress of the working groups was reported at subsequent general stakeholder meetings. The first draft of the rate handbook prepared by the working groups was posted on the Board's website in early December. After considering stakeholder comments, the working groups completed the second draft of the handbook, which was released on January 10, 2005 (the draft Handbook).

A more formal consultation was conducted by the Board to consider the product of the working group efforts. The first stage was an issues day, during which the Board determined the extent of the matters to be addressed in the rate handbook. After completion of the second draft, the Board received written evidence and heard from several expert witnesses on selected contentious issues. Subsequent to hearing from the experts, the Board received written submissions on many of the alternatives proposed in the draft Handbook.

As part of Issues Day, the Board provided some guidance to the participants respecting what it saw as the rational next steps in the evolution of ratemaking in Ontario following the production of the Electricity Distribution Rate Handbook for 2006. These steps included Board reviews of the methods underpinning cost allocation, depreciation rates and methodology, working capital, and the cost of capital and related issues.

In his letter to the industry dated March 9, 2005, the Chair of the Board confirmed and refined the Board's commitment to these reviews, and added the need for the Board to consider the implications of the implementation of new metering technology and other developments in the energy sector as it develops its ratemaking plans for subsequent years. This is an aggressive agenda, which requires a significant commitment from all participants if it is to be achieved within the current projected timeframe.

Each chapter of this Report corresponds to the same chapter in the Rate Handbook. The Board does not address every item in the Handbook in this Report. Generally speaking, if a consensus was developed in the working groups and was not opposed in the submissions, then that consensus is reflected in the Handbook. This Report will address the following items:

- issues for which a consensus was not reached
- any consensus position which was subsequently opposed in the submissions
- any areas where the Board has concluded that a material change is required to the consensus position.

Some additional modifications have been made to the Handbook in order to enhance its clarity. Those changes are not discussed in this report unless they are material.

CHAPTER 1: INTRODUCTION

Chapter 1 provides an overall introduction to the 2006 Handbook. The chapter outlines the components of the application and the filing dates. A number of proposals were made for additions or refinements.

Issues and Conclusions

The Association of Major Power Consumers of Ontario (AMPCO) proposed additional wording to emphasize that the Handbook relates to 2006 only and to summarize the further reviews in 2007 and 2008. The Consumers Council of Canada (CCC) expressed similar concerns. The Board agrees that the 2006 Handbook is for 2006 rates only, and the Introduction clearly says so. The Board has communicated its plans for 2007 and 2008 through a number of channels, including at the beginning of this Report, and will continue to communicate on these issues. The Board concludes that no additions to the 2006 Handbook in this respect are required.

Toronto Hydro appeared to suggest that the filing deadline for all applications should be delayed until the Handbook and the model are in “workable condition”. CCC also expressed concerns about the filing deadline. Schools Energy Coalition (Schools) opposed any delay that would reduce the time available to process the applications. The Board is sensitive to concerns regarding the tight timeframes and the pressure that these place on stakeholders. However, the Board does not believe that delaying applications, pending further revisions to the Handbook, will provide an appropriate solution. Applicants will proceed on the basis of the Handbook and Model as they are released. If material revisions are subsequently required, the Board will deal with them in due course.

Hydro Ottawa proposed that a later filing deadline of September 1, 2005 be set for distributors filing on a forward test year basis. The Board agrees with Hydro Ottawa that a forward test year application will entail greater detail and more work on the part of the distributor. A forward test year application will also require greater effort on the part of the Board and stakeholders to evaluate. The Board will therefore not set a later filing deadline for forward test year applications in the Handbook.

The Board has determined that a single filing deadline for all distributors will not be the most efficient for purposes of processing the applications in a timely manner. For that reason, the Board has decided that it will prescribe three filing deadlines, generally requiring earlier filings from larger distributors. The Handbook contains the details of the filing schedule.

Schools proposed extensive additions related to consultation prior to filing, provision of applications to stakeholders, and the role of stakeholders. Its proposals were opposed by a number of distributors on the grounds that they were unnecessary or that they were procedural and therefore not within the purpose of the Handbook. While the Board agrees with some of the sentiments expressed by Schools, in particular regarding cooperation between applicants and intervenors, the Board does not believe the Handbook is the appropriate place to articulate procedural expectations. The Handbook is a filing guideline; it is not a process guideline.

CHAPTER 7: TAXES AND PILS

Chapter 7 of the 2006 Handbook explains how a distributor should calculate the amount of corporate income and capital tax expense to be included in its 2006 rates application. The Board will issue a 2006 regulatory tax calculation model that reflects the Board's conclusions, and distributors will use this model in their applications.

The following issues are addressed in this report:

- general principles
- true-up
- tax savings arising from non-recoverable or disallowed expenses, including purchased goodwill and charitable donations
- fair market value "bump"
- loss carry-forwards
- interest deduction
- sharing of tax exemptions
- undepreciated capital cost (UCC) and capital cost allowance (CCA)
- regulatory assets and liabilities
- CDM
- Smart Meters
- tax information disclosure

General principles

Stakeholders raised a number of issues in the area of general principles, many of which go to the objectives of setting the tax provision in rates. Where the term 'PILs' is used, the comments also apply to corporate taxes where the distributor pays taxes to the federal government.

The Draft Handbook indicates that the explanatory detail in the chapter may be removed in the final version of the chapter. However, Schools suggested that some background explanation should remain, so that readers can better understand the changes from past practice and hence improve compliance. LPMA also proposed additional wording related to the "stand-alone" principle, under which ratepayers only bear the costs, risks and benefits arising from the provision of regulated services.

In the section on regulatory taxes payable method, the Draft Handbook contains the following: "The tax amount included in rates is based upon taxes expected to be actually payable as a result of operating the distribution-only business, rather than upon taxes calculated for accounting purposes." The Coalition of Issue Three Distributors (CITD) submitted that the references to "taxes payable expected to be incurred" and "taxes expected to be actually payable" should mean the amount the Board calculates for ratemaking purposes, not the amount the distributor will calculate on its tax return.

LPMA submitted that the wording in the section on prudent management of taxes should be revised to state that a distributors is "required and expected" (rather than "allowed and expected") to manage taxes prudently.

Conclusions

Taxes are an important component of the overall revenue requirement. The Board has four guiding principles when determining the allowance for taxes in 2006 rates:

- The tax rates and tax rules used in the tax model should reflect to the extent possible the actual rates and rules that will be applicable in 2006.
- The inputs to the calculation should be consistent with the other components of 2006 rates.
- Rates must be just and reasonable, and any substantial variation between taxes determined for regulatory purposes and actual taxes paid by the distributor must be justifiable.
- The tax model should be reasonably simple.

Practically speaking, the third and fourth principles balance the first and second principles. The second principle incorporates the concept of the "distribution-only" business, or "stand-alone" distributor, but that cannot be the Board's only consideration.

The Board notes the concerns expressed by stakeholders regarding the potential difference between the level of actual taxes paid and the level allowed in rates. The Board intends to continue to monitor actual taxes paid and taxes recovered through rates to determine whether modifications to the Board tax methodology, or its application in the Board tax model, are required for future years. This will include an analysis of the differences between these two amounts, and a determination of the reason(s) for any material difference.

The Report will now address the specific initial issues raised. The conclusions reflect the application of the general principles outlined above.

The Board will retain sufficient explanation in the Handbook so that distributors and other stakeholders can understand the Board's objectives in this area and to assist a distributor in making accurate filings. A lengthy section on the "stand-alone" principle will not be included. The Board has addressed the stand-alone concept throughout this chapter of the Report, and the issue is dealt with directly in the section on tax savings arising from disallowed expenses. The Board believes this is sufficient to aid the understanding of stakeholders at this time.

With respect to the prudent management of taxes, the Board expects a distributor to manage taxes prudently and will set rates accordingly, but the Board is not explicitly "allowing" or "requiring" it to do so. The Handbook will be adjusted accordingly.

The draft Handbook includes a section on "PILS tax administration and tax rulings", which states that "the applicant's initial 2006 tax payable filing must account for the tax effect of the ruling or policy", if that policy or ruling is inconsistent with the 2006 OEB Tax Model. The Board has determined that this will not be required as part of the application; rather, for purposes of the application, an applicant will only be required to disclose the new policy or ruling.

True-up

The Draft Handbook contains two alternatives for the determination and recovery of the variance between taxes paid and taxes included in rates, otherwise known as the "true-up". Alternative 1 provides a partial true-up for tax driven factors, and Alternative 2 provides a full true-up for tax driven and operations driven factors:

- Alternative 1: Each distributor shall establish a 2006 PILs/taxes variance account to capture the tax impact of the following differences:
  - any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model
  - any difference that results from a change in, or a disclosure of, a new assessing or administrative policy of the Federal or Provincial tax authorities, if the Board has declared that such new or modified assessing or administrative policy is a change of general application that should be treated as if it were a change in tax rules
  - any difference in 2006 PILs that results from a tax re-assessment which is received by the distributor after its 2006 rate application is filed, and before May 1, 2007, and which relates to any tax year ending prior to May 1, 2006
- Alternative 2: A variance account will be set up for 2006 PILs/taxes. Any variance between actual taxes and forecast taxes should be credited or debited to this account, and should be cleared to ratepayers in the following year.

Toronto Hydro sponsored evidence by Mr. Krukowski and Mr. Erling of KPMG. Their conclusion was that the partial true-up is the most appropriate option because it results in less administrative burden, greater rate stability, and lower risk to distributors. They testified that with full true-up, the rate changes would magnify the earnings volatility arising from variations in revenue or expenses, and inappropriately pass the tax consequences to ratepayers.

Most distributors supported Alternative 1, in line with the KPMG recommendations. Schools, CME, LPMA, and VECC also supported the partial true-up.

Amongst distributors, only London Hydro and Niagara Erie Public Power Alliance (NEPPA) supported the full true-up. Enbridge and Union did not support any true-up.

There was also some discussion regarding the scope of the proposed true-up for prior year tax re-assessments and whether the wording in Alternative 1 accurately captured the intended effect. Stakeholders generally agreed that the intention was that the true-up of 2006 taxes relating to re-assessments of prior taxation years would deal only with the impact on 2006 taxes of those re-assessments.

In addition to changes in tax rates, rules and re-assessments, which are unambiguous, the partial true-up approach is also proposed to include “new or modified assessing or administrative policy” if the Board declares that the policy change is of general application and should be treated as a change in tax rules.

To paraphrase Schools, the issues with respect to this policy change provision are:

- How will the Board know that a change in policy has occurred?
- How will the Board determine whether such a change should be treated as being equivalent to a change in tax rules?

Schools submitted that changes are either communicated publicly through bulletins, circulars, and public rules or through individual audits or private rulings. In Schools’ view, the Board should receive any public information directly and distributors should be directed to inform the Board of any changes which come to their attention, for example through an audit. Schools submitted that any changes that are published would be of general application and that the Board could assess any changes that arose through an audit. Schools acknowledged that this latter assessment could be complex.

Conclusions

The Board will adopt the partial true-up approach. The Board agrees that it would be inappropriate to adjust rates to account for tax differences arising from variations in revenues or expenses. The Board also accepts that a partial true-up for changes in tax rates, rules, etc. represents a reasonable balance of risk between shareholders and ratepayers for items which are beyond the control of the distributor.

The Board will revise the wording in the Handbook related to the true-up for prior year tax re-assessments so that the description of what is in the variance account addresses the issue of opening balances directly and is consistent with the intention as expressed in the “Tax re-assessments” section.

With respect to changes in policy, the Board will narrow this adjustment provision, in order to reduce the amount of discretion required and the amount of regulatory process needed. The Handbook will be revised to include only those changes in tax policy that are published in the public tax administration bulletins or interpretations by relevant federal or provincial tax authorities. The approach proposed by Schools, which includes policy changes arising from individual audits, introduces a level of complexity and additional regulatory burden that is not warranted in the circumstances

Tax savings arising from non-recoverable or disallowed expenses, including purchased goodwill and charitable donations

There are a number of situations where the distributor may be entitled to tax deductions for expenses or other items that are not allowed for regulatory purposes. The Draft Handbook identifies a number of these situations:

- Non-recoverable or disallowed expenses
- The impact on Eligible Capital Expenses (or Cumulative Eligible Capital) related to disallowed expenses (Purchased Goodwill)
- Charitable donations

The treatment of the resulting tax savings in each of these situations is in dispute. The Draft Handbook sets out three alternatives in each case:

- The tax savings are shared between ratepayers and shareholders.
- The tax savings go to ratepayers.

- The tax savings go to the shareholder.

Schools sponsored evidence by Dr. Mintz of the C.D. Howe Institute. Dr. Mintz, a tax expert, testified that tax savings in the specified situations should flow to ratepayers. In his view, to do otherwise would result in:

- ratepayers subsidizing the disallowed expenses;
- incentives being created to inappropriately alter the distributors capital structure or expenses to maximize the tax benefits;
- delayed repayment of the stranded debt; and
- a departure from competitive market results, whereby any reductions in actual taxes paid result in lower prices to consumers.

The Coalition of Issue Three Distributors (CITD)[1] sponsored evidence by Ms. McShane. Ms. McShane, a regulatory expert, testified that the tax provision for a distributor should be determined on the basis of the following principles:

- Benefits follow costs: the party bearing the cost should receive the tax saving.
- Stand-alone utility: only the costs and risks related to the utility operations should be in the revenue requirement.
- No harm to ratepayers: a “minimum” condition that specifies that ratepayers must be no worse off.
- Level playing field among gas and electricity distributors.

Applying each of these principles, Ms. McShane concluded that the tax savings in the specified situations should flow to the shareholder.

CITD adopted the position of Ms. McShane; namely, that in applying the regulatory principles and the government’s objective of a level playing field, the conclusion is that

[1] The Coalition of Issue Three Distributors includes Aurora Hydro Connections Limited, Barrie Hydro Distribution Inc., Cambridge and North Dumfries Hydro Inc., Chatham-Kent Hydro Inc., ENWIN Powerlines Ltd., Guelph Hydro Electric Systems Inc., Halton Hills Hydro Inc., Hydro One Networks Inc., Innisfil Hydro Distribution Systems Limited, Kitchener-Wilmot Hydro Inc., Newmarket Hydro Ltd., Orangeville Hydro Ltd., Orillia Power Distribution Corporation, Tay Hydro Electric Distribution Company Inc., Toronto Hydro-Electric System Limited, Waterloo North Hydro Inc., Westario Power Inc., Whitby Hydro Electric Corporation.

the tax savings should flow to distributor and thus to the shareholder(s), rather than to the ratepayer. CITD maintained that this was accepted regulatory practice, and reflected that the tax savings arise from costs that the ratepayer did not bear.

Hydro One, PowerStream and Toronto Hydro supported the submissions of the CITD and highlighted certain points:

- The fact that under current government policy PILs is being used to pay down the stranded debt is not relevant to how the amount of PILs to be paid should be calculated. The fact that the province allows an expense to be deductible for tax purposes is a matter of provincial tax policy, not ratemaking.
- A distributor would generally not incur a disallowed expense, and therefore passing on a tax saving to ratepayers, that did not occur, would increase the inequitable treatment.
- Schools' proposal implies that a distributor would undertake activities that violate the *Electricity Act*, the *Ontario Energy Board Act*, the Affiliate Relationships Code and the *Municipal Act,* and that the Board should address these violations indirectly through the tax calculation rather than directly.

LPMA supported the principles identified by Ms. McShane, and submitted that in a normal regulatory environment LPMA would support Ms. McShane's conclusions. However, LPMA submitted that tax savings should flow to ratepayers because PILs are used to pay down the former Ontario Hydro stranded debt. The tax savings are therefore a "cost" to ratepayers. LPMA goes on to apply Ms. McShane's regulatory principles to come to the opposite conclusion of Ms. McShane. In LPMA's view, any tax savings is a <u>cost</u> to ratepayers, without any benefit in those cases where the cost is disallowed. LPMA concluded that if the Board were to decide that tax savings from disallowed expenses were not to go to ratepayers, then the Board should inform the government as to the negative impacts on ratepayers and the level of debt.

Conclusions

The Board finds that tax savings arising from the specified situations will not be allocated to ratepayers. The regulatory principles identified by Ms. McShane are applicable in this situation. What is at issue is how those principles are to be applied and whether there are sufficient grounds to depart from them in these circumstances.

Schools has argued, in effect, for a departure from these established regulatory principles for four primary reasons:

- If the tax savings are not allocated to the ratepayer, then the ratepayer is effectively "subsidizing" the disallowed expenditure.
- If tax savings flow to shareholders, then the shareholder, because it is a non-taxable entity, will have an incentive to use the distributor as a "tax shelter" and to incur expenses or alter the distributor's capital structure inappropriately. For example, there would be an incentive to finance the distributor with 100% debt.
- In a competitive market, any reductions in tax paid would generally result in lower prices.
- PILs payments are used to pay down the stranded debt. If tax savings go to the shareholder, then rates will be set with a higher provision for taxes than will actually be paid. Ratepayers will repay a certain amount of the stranded debt through the regulatory tax calculation, but the full amount will not be remitted as PILs because of further deductions by the distributor. In effect, the ratepayers will have to pay twice.

The Board does not believe that any of these arguments supports a departure from standard regulatory practice and established regulatory principles.

With respect to the first point, the Board does not agree that if the tax savings are not allocated to the ratepayer, then the ratepayer is effectively "subsidizing" the disallowed expense. Schools argued that if the distributor incurs the disallowed expense, then it would be inappropriate for the tax benefit to flow to shareholders (by being excluded from the rates). However, Schools agreed that if the shareholder incurred the disallowed expense within another (tax paying) entity, then it would be appropriate for the tax benefit to flow to the shareholder. Dr. Mintz also agreed with this. The Board finds this reasoning to be inconsistent with the claim that in one scenario the ratepayers are somehow “subsidizing” the shareholders; the level of taxes included in rates is the same in both scenarios. The issue remains as to whether the distributor has behaved appropriately in undertaking the disallowed expenses, and that issue is addressed under the next point.

With respect to the second point, the Board accepts that because municipalities are non-taxable, there may be an incentive to allocate expenses and adjust the capital structure of the distributor to maximize the tax advantages. However, there are limits on what actions can be taken. These limitations arise from various statutes, and are intended to ensure that customers are protected and the financial viability of the distributor is maintained.

Schools suggested that these limitations are not sufficient in the case of municipal distributors and maintained that preventing inappropriate behaviour by taking away the tax incentive is the “most elegant way to get the right result”. The Board disagrees. The tax approach would require the Board to impute tax savings, which would then need to be adjusted if the expenditures did not occur. Alternatively, there would need to be an after-the-fact investigation of tax deductions to look for “disallowed” amounts. In the Board’s view this is not “elegant”. It is administratively complex, and still fails to get to the nub of the issue, which is the inappropriate behaviour. If a distributor engages in inappropriate activities, then the Board should address the matter directly.

Schools appeared to be particularly concerned about inappropriate social spending and capital structure changes. The Board is satisfied that section 71 of the *Ontario Energy Board Act* provides the requisite protection against inappropriate expenditures by a distributor. When the Board conducts its review of cost of capital and capital structure, it will consider in more depth the relationship between capital structure, interest expense and taxes and determine the appropriate regulatory framework. This issue is addressed further in the section on interest expense. The Board is satisfied that its provisions for tax information disclosure, addressed later in this section, will allow for adequate monitoring of these issues.

With respect to the third point, the Board accepts the evidence of Dr. Mintz that in a competitive market tax reductions will tend to lead to lower prices, but does not agree with his conclusion that the tax savings of disallowed expenses should be passed on to ratepayers. Such an approach takes no account of the increased expenditures from which the tax savings arise. Presumably in a competitive market, if an entity incurs a cost from which a tax reduction is gained, the increased cost works its way into prices as well. A unilateral allocation of the tax savings to the ratepayers would seem to be an inappropriately simplistic application of the competitive market principle.

With respect to the fourth point, the Board does not agree that the link between PILs and the stranded debt is relevant. All tax revenues are used for some purpose, whether to fund programs or repay debt. To the extent tax deductions are allowed, there will necessarily be a reduction in funds available for those other purposes. The relationship between PILs and the stranded debt is no different. This conclusion is supported by the fact that the express purpose of PILs was to put municipal distributors on an equivalent basis with tax paying distributors. The fact that PILs payments are allocated to the stranded debt is a function of provincial policy and is not necessarily a permanent feature. Finally, the Board notes that PILs from distributors are not the only, or largest, source of funds currently paying down the stranded debt.

For all of these reasons, the Board rejects the proposal by Schools, and concludes that tax savings arising from disallowed expenses, including purchased goodwill and charitable donations, will not be allocated to ratepayers. Ratepayers have not paid for the expense through rates, and therefore are not entitled to the tax benefit.

Fair market value “bump”

The Ministry of Finance required the re-valuation of distributor assets to market value, effective October 1, 2001. This Fair Market Value Bump, or FMV Bump, adjusted the value of distributors' Cumulative Eligible Capital or Undepreciated Capital Cost. No adjustments to rate base were made for regulatory purposes. There is a potential impact on the Cumulative Eligible Capital (or Eligible Capital Expenditures) deduction or the Capital Cost Allowance. With respect to the Cumulative Eligible Capital or Undepreciated Capital Cost, the issue is whether the tax savings arising from the FMV Bump should be shared between ratepayers and shareholders, allocated 100% to the ratepayers, or allocated 100% to the shareholder.

The positions and reasoning taken by each of the parties were largely the same for this issue as for the previous issue of tax savings arising from disallowed expenses.

CITD maintained that while no "cost" has been incurred, the tax savings would be subject to recapture if the assets are sold at fair market value, and therefore it is essentially a temporary benefit. Hydro One submitted that because the tax benefit is recaptured upon sale of the assets or change in tax status, ratepayers would have to compensate the distributor for that recapture if they are to benefit from the tax benefit. Schools essentially agreed that recapture of the benefit might occur and submitted that ratepayers should get the savings now, and that the Board should address the recapture at the time of the future transaction.

Conclusions

The Board finds that any tax savings resulting from the FMV Bump will be allocated to the ratepayers. It is true that the rates themselves are based on book value not market value, which suggests that under the stand-alone principle the FMV Bump should be disregarded. However, the shareholder has not incurred any cost related to the change in value for tax purposes (as CITD acknowledged), so the "benefits follow costs" principle is not applicable. In addition, the FMV Bump could be characterized as a change in the tax rules, and therefore would fall into the category of changes subject to true-up. Ms. McShane testified that the savings would be subject to recapture and Hydro One submitted that if the ratepayer benefits from the FMV Bump, it should also be liable for the recapture. The Board agrees that if the ratepayers benefit from this tax saving, then any subsequent recapture should be considered for recovery from ratepayers as well. However, the Board has no evidence as to how frequently or to what extent this recapture will take place.

While the Board cannot address the recapture at this point, it can address the current tax savings. The Board has determined that the 2006 tax calculation will incorporate the impact of the FMV Bump. If at some point a related tax liability arises from a sale of assets or change in tax status, then the distributor will be able to apply to the Board for relief, at which point the issue will be determined. The Board notes that this approach will reduce the variance between actual taxes and the tax provision in rates, that it will not disadvantage the shareholder because the shareholder incurred no cost, and, if there is subsequent recapture, the distributor may apply to the Board for relief.

Loss carry-forwards

The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.

Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 tax calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.

Conclusions

The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for other reasons that may be related to ratepayers. The Board notes that the consensus approach will reduce the variance between taxes collected in rates and actual taxes paid. The Board will adopt this approach in the Handbook. However, the Board has concluded that a projection of this factor to 2006 will not be required as this represents unnecessary complexity for purposes of 2006 rates.

Interest deduction

At issue is the amount of the interest to be deducted for the regulatory tax calculation. The Draft Handbook contains four alternatives:

- Deemed (recoverable) interest expense
- Actual interest expense
- The greater of deemed (recoverable) and actual interest expense
- Share of additional interest expense (above the deemed level)

Currently, taxes are determined using the deemed interest expense, but the Board has previously indicated its intention to true-up this component of taxes to reflect actual interest expense, and the difference is being captured in the variance account.

CITD supported the first alternative, namely the deemed interest expense used for ratemaking purposes. EDA, Hydro One, Toronto Hydro, ECMI, NEPPA, Union, and CME were all of the same view.

Schools supported the third alternative, namely that the greater of the deemed or actual interest expense should be used. It relied primarily on concerns about the incentive for a distributor or its shareholder to adjust the distributor's capital structure to minimize taxes. LPMA made similar submissions.

Conclusions

Under the stand-alone principle, the level of interest used in the tax calculation should be the same as the deemed level of interest included as a distribution expense in the revenue requirement. However, the Board agrees that the incentive may exist to alter the capital structure in a way that substantially benefits the shareholder in terms of reducing actual taxes paid. The resulting difference between taxes paid and taxes collected through rates may be of sufficient magnitude to call into question whether the resulting rates are just and reasonable.

Contrary to Schools submission, the Board does not agree that the best way to deal with this issue is through the tax calculation. The Board should consider whether alternative capital structures (and associated tax implications) are appropriate, rather than just implement disincentives to deviate from the deemed capital structure. The Board's conclusion is that this issue should be dealt with comprehensively at the time of the capital structure and rate of return review (as described previously). As part of that review the Board will consider, among other things, the tax implications of various capital structure strategies and will determine the most appropriate overall approach for ratemaking purposes.

However, for purposes of 2006, the Board will continue the current treatment but refine it such that the tax calculation will be based on the greater of the deemed and actual 2004 interest expense, including the Tier 1 and 2 adjustments. Applicants will be required to file information regarding the actual debt ratio and interest cost.

Sharing of tax exemptions

The Draft Handbook states that the federal large corporation tax exemption and Ontario capital tax exemption will be prorated when multiple regulated entities are in the same corporate group. With respect to the prorating of any tax exemption between the distribution and non-distribution functions in the same legal entity, the Draft Handbook contains two alternatives: one alternative is to prorate; the other is not to prorate.

LPMA submitted that these tax exemptions should not be prorated amongst regulated entities within a corporate group. LPMA argued that to do so would violate the stand-alone principle, because if the distributor were stand-alone, then the full LCT exemption would apply. The result of the treatment in the Draft Handbook is that customers would face higher rates as a result of the corporate affiliates sharing the LCT exemption. Similarly, LPMA submitted that there should be no pro-rating of the exemptions between distribution and non-distribution functions.

Hydro One, Toronto Hydro, Union, CME and VECC all supported the pro-rating of the exemption between distribution and non-distribution functions.

Conclusions

The Board agrees that the stand-alone principle is applicable in this situation and that the federal large corporation tax and Ontario capital tax exemptions should be determined without a prorating between distribution and non-distribution functions. However, the exemptions will be prorated among regulated entities within the same corporate group. Although this is not a strict application of the stand-alone principle, it recognizes that there has been, and continues to be, consolidation among Ontario distributors. Given that those corporate structures are evolving and rate harmonization is not complete, the Board concludes that it is appropriate to recognize the shared nature of the resulting tax exemptions and that such an approach does not deviate from the intent of the stand-alone principle.

Undepreciated Capital Cost (UCC) and Capital Cost Allowance (CCA)

The Draft Handbook states that the CCA calculation in the OEB 2006 PILs model should be based upon 2004 actual UCC and the allowed Tier 1 and Tier 2 capital adjustments. The applicant is also to assume new additions in 2005 equal to 2004 capital expenditures. A similar approach is used to set the values for 2006. In effect, the UCC is inflated from 2004, based on additions in 2004 and the Tier 1 and Tier 2 adjustments, to create a proxy for 2006.

Hydro One submitted that the proposed adjustments would be inappropriate. In its view, the adjustments would result in the PILs calculation being based on a higher rate base amount than that used to determine the equity return and book depreciation. In its view, this would have the effect of reducing the shareholder’s allowed equity return. Hydro One submitted that the base should be 2004 actuals plus any applicable Tier 1 and Tier 2 adjustments only.

Conclusions

The Board agrees that rate base and undepreciated capital cost (and therefore the capital cost allowance) should generally be determined on a consistent basis. The adjustments contained in the Draft Handbook could be characterized as a quasi-forward test year approach. The Board concludes that these adjustments represent an unjustified inconsistency with the determination of the other components of the revenue requirement for applications based on an adjusted 2004 historical test year. The Board will adopt the more simplified approach of using 2004 actuals plus any Tier 1 and Tier 2 adjustments. This approach would not be applicable to those distributors filing on a forward test year basis.

Regulatory assets and liabilities

A PILs or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their tax returns. The Handbook will reflect this treatment.

CDM and Smart Meters

The issue is how the 2006 regulatory tax calculation should take account of CDM and Smart Meters capital and operating expenditures. The Board addresses CDM in detail in Chapter 16 of this Report. To the extent incremental CDM and/or Smart Meter expenditures are approved, they will form Tier 1 adjustments and will be treated accordingly for purposes of taxes.

Tax information disclosure

The Draft Handbook requires the distributor to disclose the actual corporate taxes or PILs paid in 2006 and the amount collected in 2006 rates, with any differences greater than 10% to be explained in a future filing. At issue is whether a distributor that does not have a separate tax return for the distribution portion of the business should be exempted from this requirement.

Hydro One and ECMI supported the exemption. NEPPA argued that filing audited financial statements for the wires-only company might place unnecessary risk on a subsidiary business and that any filing, including supporting documentation, should be confidential.

Schools did not support the exemption and suggested that individual requests for exemption should be brought to the Board. The Board could then determine the appropriate means for disclosure.

Conclusions

The Board finds that the requirements will apply for all distributors. There must be transparency in the regulatory process. It remains open to a distributor to request an individual exemption, and the Board will consider such a request on its merits. It is also open to a distributor to request that tax information be kept confidential, and a determination would be made be the Board at the time the request is made.