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D R A F T

Understanding the proposed amendments to the Affiliate Relationships Code for Gas Utilities:

An OEB Background Policy Paper

March 15, 2004

Contents

A. Introduction

1. What this paper does

The Ontario Energy Board (the Board) is issuing this Background Policy Paper along with its package of proposed amendments to the Affiliate Relationships Code for Gas Utilities (the ARC). This paper describes:

- The proposed changes to the transfer pricing rules in the ARC
- Why the changes are being proposed
- How the Board proposes to interpret the new rules.

By releasing this paper, the Board hopes to provide stakeholders with insight into the policy rationales underlying the proposed changes to the ARC. It is important reading for stakeholders wishing to comment on the proposed amendments as part of the rule-making process.

2. How to read this paper

Although this paper is being released with the proposed ARC amendments, it is written in such a way that it can be read on its own. Each change is adequately described so there is no need to continually refer back to the ARC and the proposed amendments.

All of the proposed amendments are addressed in this document, though not necessarily in order. Section numbers are given in the headings for ease of reference.

Shadow boxes contain interesting facts and background information

Shadowed boxes, like this one, contain interesting tidbits that may interest you. Historical facts and information from other jurisdictions can be found here. Full references are given whenever possible to help you look things up. If you are short of time, you can skip over these boxes

Plain text boxes contain Board's interpretive guidance

Our proposed interpretive guidance appears in plain text boxes, like this one. However, the Board will not be bound by the guidelines. The Board may choose to vary from these guidelines in the particular circumstances of an individual case.

B. Background and overview

1. How the proposed amendments came about

a. The ARC and the transfer pricing rules

The ARC was brought into force on July 31, 1999 to codify rules that were previously contained in undertakings given to the Province by utilities. The ARC governs the terms under which a utility can conduct business with an affiliated entity. The transfer pricing rules in the ARC regulate how much a utility can charge or pay when it does business with an affiliate.[1]

The pre-1999 undertakings system

Before 1999, affiliate transactions rules could only be found in undertakings the natural gas utilities signed with the Province when changes in their ownership took place.

Gas utilities still have undertakings in place, but they no longer address transfer pricing because these rules have now been codified in the ARC.

b. The trend towards outsourcing core functions

Before the ARC came into force, most outsourcing was driven by the desire to centralize utilities' corporate services outside of Ontario to reduce costs. By the end of the millennium, there was an increasing trend towards outsourcing core utility functions to affiliated businesses in order to compete more freely in the deregulated and unregulated segments of the industry.

c. Recent rate hearings

The Board was faced with a number of issues around the interpretation of the transfer pricing rules during the fiscal 2002 and 2003 rates hearings for Enbridge Gas Distribution Inc.[2] As a result, the Board indicated in the Enbridge 2003 test year decision that it was undertaking a review of the ARC on its own initiative.

The Board has now completed its review of the ARC against the backdrop of both prior Board decisions and North American best practices. The proposed amendments are the product of this review.

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[1] Readers who are interested in a discussion of what led North American regulators to introduce transfer pricing rules are directed to the (U.S.) Securities and Exchange Commission Report, The Regulation of Public-Utility Holding Companies, June 1995.

[2] Decision with Reasons, RP-2001-0032, issued 2002 December 13 (the Enbridge 2002 test year decision) and Decision with Reasons, RP-2002-0133, issued 2003 November 07 (the Enbridge 2003 test year decision).

2. Nature of the proposed amendments

a. Fine-tuning the current approach

The proposed amendments build on the foundation of the current transfer pricing rules. The amendments represent a fine-tuning of the current system, rather than a substantial shift in policy.

b. Potential win-win outcomes

The current general approach holds the promise of a win-win outcome. The Board believes that a vigorous outsourcing market can lead to both ratepayers and utilities benefiting over time, as competitive pressures encourage affiliates to become increasingly efficient in their transactions with utilities. The amendments proposed are intended to strengthen the potential for win-win outcomes, while ensuring, at a minimum, that ratepayers suffer no harm from outsourcing.

The current approach

- Market-based pricing should be used if a market exists.
- Cost-based pricing should be used if a market does not exist.

A U.S. study (Cost allocation and Affiliate Transactions: A Survey and Analysis of State Cost Allocation Issues and Transfer Pricing Policies, Edison Electric Institute, 1999) noted use of the same basic approach:

- Fair market value should be used unless market value cannot be established, in which case fully allocated costs should be used

c. Underscoring the importance of the competitive markets

The proposed amendments reinforce the Board's view that the competitive markets should be relied upon, whenever possible, to deliver pricing benefits to ratepayers. The Board continues to believe a competitive bidding system—one in which market forces operate freely—represents the best method of obtaining goods and services. The proposed amendments are designed to mandate the use of competitive bidding where a market exists for the outsourced service or product.

What are other regulators up to?

When reviewing Bell Canada's affiliate relationships, the CRTC commented:

> "The Commission concludes that, as a general rule, the company should undertake a competitive bidding process when an affiliate is an actual or potential supplier of goods or services" (Telecom Decision 90-17).

d. Updating the cost-based pricing rule

In the absence of a competitive market for an outsourced service or product, a cost-based pricing rule would still come into play under the proposed amendments, as they do under the current rule. However, the Board proposes to change the language of the rule to make it easier to apply.

C. Discussion of proposed amendments

1. Purpose of this Code

a. Summary of changes

The Board plans to update the purpose section of the ARC. The amendment will articulate the underlying purpose more clearly.

b. Section 1.1: The "no-harm" objective is clarified

It is proposed that section 1.1 of the ARC ("Purpose of the Code") be amended to clarify that:

> The principal objectives of the Code are to enhance a competitive market while, *at a minimum*, keeping ratepayers unharmed by the actions of gas distributors, transmitters and storage companies with respect to dealings with their affiliates.

In other words, not harming ratepayers is only a minimum condition. The intent of the new language is to accommodate the possibility that ratepayers may realize benefits from outsourcing (as discussed below).

c. Facilitation of ratepayers benefits also a policy goal

In designing the package of proposed amendments (increased role for tendering, etc.), one of the policy goals the Board seeks to advance is to "facilitate" ratepayers benefiting from outsourcing over the long run.

2. Transfer Pricing: Where a Market Exists

a. Summary of changes

The Board would like to clarify that the market price must be used where a market exists, and that market price should generally be determined using a competitive bidding process. The proposed changes to the language are intended to remove any ambiguity. In the interests of balancing the costs and benefits of competitive bidding, smaller-dollar contracts will be exempted from the requirement for mandatory competitive bidding. The proposed amendments also include a requirement that larger transactions be reviewed by an independent evaluator. This measure is designed to promote transparency.

b. Sections 2.3.4 and 2.3.9: "Fair market value" is changed to "market price"

> **Comparisons with other regulators.**
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> The National Association of Regulatory Utility Commissioners' (NARUC) Guidelines use the term "prevailing market price", which is defined as "a generally accepted market value that can be substantiated by clearly comparable transactions, auctions or appraisal" (see "Guidelines for Cost Allocation and Affiliate Transactions", March 8, 2000).

It is proposed that where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall pay no more, or charge no less than, the prevailing *market price* when transacting with an affiliate. Many North American codes use this terminology, and the Board will do so as well to further emphasize that the transfer price should be objective. The Board does not intend a change in policy by the new term. The actual definition will remain the same, and it is consistent with the definition used in the electricity ARC.

c. Section 2.3.5: A fair and open competitive bidding process is made mandatory

It is proposed that a *competitive bidding process* shall be used to establish the market price before a utility enters into or renews a contract with an affiliate. The Board believes that a competitive bidding process is the best means of establishing that a fair price is paid.

The words "competitive bidding process" would replace "tendering," which is used in the current rules. The Board chose the new language because it is more generic.[3]

It is further proposed that the competitive bidding process followed should be *fair and open*. This language was used by the Board in its Enbridge 2003 test year decision[4] and similar language is used by other regulators.

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[3] The Board understands that tendering is also a specific type of bidding process. See part III (Competitive Bidding) of CRTC Telecom Decision 90-17.

[4] RP-2002-0133 at line 507.

What constitutes a fair and open competitive bidding process?

There are a variety of ways to organize competitive bidding. The Board will accept any reasonable process, provided it is conducted in a fair and open manner.

Whether a fair and open competitive bidding process was actually followed by a given utility is a question of fact that can be reviewed in a rate hearing. For example:

- If an affiliate were the sole bidder, or if the affiliate were awarded the contract where it was not the lowest bidder, the tendering process would be subject to heightened scrutiny by the Board.
- If an affiliate were allowed to match any offer provided by another bidder, the Board would assume a fair and open competitive process had not been followed.

The Board may also be concerned if a RFP is drafted in a way that discourages bidding.

d. Section 2.3.6: A threshold is set for competitive bidding

It is proposed that smaller-dollar contracts be exempted from the competitive bidding requirement. This threshold would be set to address concerns that the cost of organizing a competitive bidding process will outweigh the benefits. The Board proposes a threshold based on the higher of a fixed dollar amount ($100,000) or a percentage test (0.1% of revenues, net of commodity cost).

The effect of the proposed fixed dollar test is that smaller utilities will be exempt from mandatory competitive bidding where the contract is worth less than $100,000. The effect of the proposed percentage test is that the largest utilities in the Province will be exempt from mandatory competitive bidding for contracts under the $800,000 range.

What if a market exists but the value of the contract is below the threshold?

Where a market exists but the value of the contract is below the threshold, utilities will be allowed to use a variety of techniques to estimate the prevailing market price. This could include benchmarking and shadow tendering. Note that “shadow tendering” (where a utility seeks price quotes from third parties but does not plan to award the contract to them) will not be acceptable for contracts above the $100,000/0.1% threshold, as the Board does not consider it to be consistent with a fair and open competitive bidding process.

e. Section 2.3.7: A requirement for independent evaluation is introduced

The Board proposes to require utilities to retain an independent evaluator to evaluate whether bids on larger contracts meet the criteria for the competitive bidding process set by the utility. As U.S. anti-trust officials have explained:

> "A critical element of workable bidding systems is the perceived and actual objectivity of the bid evaluation. The system must be perceived as objective in order to attract bidders. Potential bidders, other than affiliates, may be unwilling to incur the costs of making a bid if the system is perceived as biased in favor of affiliates. The system must also be objective in fact in order to avoid raising costs for customers of the regulated utility. The use of third-party evaluations of the bids is one technique for achieving such objectivity."[5]

What are other regulators up to?

Mandatory use of an independent evaluator has already been implemented in certain U.S. jurisdictions. For example, Chapter 25.273(d)(2) of the Texas PUC Substantive Rules provides:

> The utility shall use an independent evaluator when a competitive affiliate's bid is included among the bids to be evaluated. If an independent evaluator is required, the utility shall maintain a record of communications with the independent evaluator. The independent evaluator shall identify in writing the bids that are most advantageous and warrant negotiation and contract execution, in accordance with the criteria set forth in the request for proposals. The utility retains responsibility for final selection of products or services.

It is expected that this new requirement would increase the transparency of the process and promote the growth of vigorously competitive markets for outsourced services and goods.

The requirement for an independent evaluation would be limited to significant contracts for cost reasons. The Board proposes a threshold based on the higher of a fixed dollar amount ($300,000) or a percentage test (0.3% of revenue, net of commodity costs). Under the suggested threshold, smaller utilities will not be required to retain an independent evaluator unless the value of the contract exceeds $300,000. The largest utilities in the Province will not need to retain an independent evaluator for contracts below the $2,500,000 range.

The Board would like to emphasize that the role to be played by the independent

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[5] Comments of the Staff of the Bureau of Economics of the Federal Trade Commission before the Louisiana Public Service Commission re Affiliate Relationships (Docket Number U-21453), dated October 30,1998. See section V, Limits on Transactions between Utilities and their Affiliates.

evaluator will be quite circumscribed: it is proposed that the bids be evaluated against the utility's *own criteria*.

How should utilities apply the threshold tests?

Note that both the proposed threshold tests (in sections 2.3.6 and 2.3.7) are based on the total dollar value over the life of the contract. Some outsourcing contracts may not have a fixed dollar amount. In such cases, the utility should make a reasonable estimate of the likely total dollar value of the contract. An internal budget estimate may be useful for this purpose.

f. Section 2.3.8: An anti-avoidance measure is introduced for thresholds

The Board proposes to add an anti-avoidance rule that would prevent utilities from subdividing contracts for the purpose of avoiding the application of the two threshold tests described above:

What are other regulators up to?

The Minnesota affiliate relationship rules contain a similar anti-avoidance rule (see Minn. Stat. s. 216B.48, subd. 4).

> *The Board may, for the purposes of sections 2.3.6 and 2.3.7, consider more than one contract to be a single contract where the Board is of the view that more than one contract has been entered into for the primary purpose of setting the contract values at levels below the threshold level set out in section 2.3.6 or 2.3.7.*

3. Transfer Pricing: Where No Market Exists

a. Summary of changes

The proposed amendments will make the intent behind the cost-based rule more explicit. The current reference to "cost-based price" will be replaced with the more precise phrase, "fully-allocated cost". The Board proposes to add a number of new definitions to section 1.2 to explain the meaning of "fully-allocated cost".

Does a utility need to demonstrate that no market exists?

Yes, the Board will require cogent evidence a market does not exist before considering the application of the cost-based rule. This was indicated in the Enbridge 2003 test year decision (RP-2002-0133 at line 524).

b. Section 2.3.10: The costs in question are those of the affiliate

The current section 2.3.3 states that where a fair market value is not available, a utility shall charge no less than a cost-based price and pay no more than a cost-based price. The Board proposes to make explicit in the new section 2.3.10 that when the utility acquires goods or services from an affiliate, the utility shall pay no more than the *affiliate's* fully-allocated cost to provide it. This codifies the Board's decision from the Enbridge 2002 test year.[6]

c. Section 1.2 : "Fully-allocated cost" etc. is defined

It is proposed that the phrase "fully allocated cost" be used under the cost-based pricing rule rather than the current phrase, "cost-based price". The same general approach is recommended in the NARUC Guidelines. Many North American codes define their key terms, and the Board also proposes to introduce the following important definitions in the ARC (the wording is taken from the definitions applied to the electricity sector in Article 340 of the APH):

- "Fully-allocated cost" means the sum of direct costs plus a proportional share of indirect costs
- "Direct costs" means costs that can reasonably be identified with a specific unit of product or service or with a specific operation centre or cost centre
- "Indirect costs" means costs that cannot be identified with a specific unit of product or service or with a specific operation or cost centre, and include but are not limited to overhead costs, administrative and general expenses, and taxes.

How is a proportional share of overhead calculated?

"Companies often allocate various common overhead costs in proportion to the variable costs that can be directly attributed to the individual products." (A. Khan, *The Economics of Regulation: Principles and Institutions,* 1988 at page 78, footnote 36.) The same general approach has been favoured by the FCC (see paragraph 113 of Decision 86-564).

d. Sections 2.3.10 and 2.3.11: The authorized rate of return concept is maintained

Although the concept of fully-allocated costs generally includes an appropriate return on

[6] RP-2001-0032, paragraph 5.11.41.

invested capital, the ARC transfer pricing rules will continue to expressly provide for this under the proposed amendments out of an abundance of caution.

The ARC currently provides that the return component shall be the higher of the utility's approved rate of return or the bank prime rate. The Board now proposes that the affiliate's allowed return on capital shall be no higher than the utility's most recently *approved weighted average cost of capital*. A consequence of this approach is to confirm that the deemed capital structure of the utility must be applied to the affiliate for the purpose of determining a cost-based transfer price.

What are other regulators up to?

The same approach is taken by the (U.S.) Securities and Exchange Commission when enforcing its "at cost" rule for affiliate transactions within multi-state utility holding companies. See footnote 24, page 87, "The Regulation of Public-Utility Holding Companies", SEC, June 1995.

The proposed definition is consistent with the no-harm principle since ratepayers will be assuming responsibility for the same rate of return whether the service is provided internally or through an affiliate.[7] The actual risk profile of the affiliate would be left to management's discretion.[8]

What are other regulators up to?

The fairness of the proposed definition of an affiliate's allowable rate of return was affirmed by the North Carolina Utilities Commission in *Duke Energy Fossil-Hydro, LLC*, North Carolina Utilities Commission, Docket No. E-7, Sub 694, September 26, 2002.

Should additional profit be included in the affiliate's fully-allocated cost?

No, the affiliate's fully-allocated cost should not include profit beyond the allowed return on capital utilized. As explained by the Federal Communications Commission, allowing an affiliate a return on capital invested does not imply the affiliate is also entitled to earn an additional amount as profit (see paragraph 133, FCC Order 87-305).

In contrast, affiliates can earn additional profits under the market-based transfer pricing rule, if competitive conditions allow.

Note that the proposed cost-based pricing rule will not require affiliates to immediately pass on their efficiency gains. This means affiliates still have an incentive to pursue cost reductions.

[7] The importance of such neutrality was noted the Enbridge 2002 test year decision (RP-2001-0032, paragraph 5.11.50)

[8] As suggested in the Enbridge 2002 test year decision (RP-2001-0032, paragraph 5.11.44).

4. Section 1.2: Application of transfer pricing rules to shared corporate services confirmed

The current transfer pricing rules apply to shared corporate services, since these are intrinsically affiliate transactions. To reinforce this, it is proposed that the amended ARC include the following new definition in section 1.2:

> *Service includes a corporate service.*

Markets appear to exist for some shared corporate services (Enbridge 2002 test year decision, section 3). In such cases, the transfer pricing rule requiring competitive tendering should generally be followed.

On a practical level, the Board notes corporate services agreements are for relatively modest amounts. For this reason, many corporate service agreements are expected to fall under the threshold for mandatory competitive bidding. Should a contract fall above the threshold, utilities can request an exemption under section 1.6 of the ARC, if they believe tendering would be inappropriate in the circumstances.

5. Utility's Internal Cost

a. Summary of changes

The Board proposes to mandate that the price charged by the affiliate, after application of either the market-based or cost-based transfer pricing rule, must not exceed the utility's internal cost of providing the service or good in question at the time of initial outsourcing. This addition is driven by the no-harm principle. The Board may examine the prudence of continued outsourcing at future rate hearings if circumstances warrant.

b. Sections 2.3.2/2.3.3: A "utility's internal cost" test is introduced

Proposed section 2.3.2 states:

> *[W]here a utility acquires from an affiliate a service, resource or product which immediately prior to the contract being entered into was provided by the utility itself, the utility shall pay no more than the lesser of the amount required under section 2.3.6 or 2.3.10, whichever is applicable, and the utility's fully-allocated cost to provide the service, resource or product itself at the time the utility was providing it…*

What are other regulators up to?

Alberta has similar requirements:

> 1) If a Utility intends to outsource to an Affiliate a service it presently provides for itself, the Utility shall… undertake a net present value analysis appropriate to the life cycle or operating cycle of the services involved.
> 2) "Each Utility shall periodically review the prudence of continuing" for-profit outsourcing.

See the Alberta Energy and Utilities Board Decision 2003-040, May 22, 2003 at page 77 (the 2003 ATCO decision).

It is proposed that the utility's internal costs be calculated on a fully-allocated cost basis, rather than on a marginal cost basis. This is consistent with prior Board decisions and common practice elsewhere.

With respect to timing, the Board suggests that, when a utility wishes to outsource a function *for the first time*, the utility must undertake a comparison between its internal cost and the price quoted by an affiliate to confirm that ratepayers will not suffer any financial prejudice if the outsourcing plan proceeds.

c. Periodically revisiting utility's internal cost

Other regulators have expressed the desirability of periodically reviewing the prudence of continued outsourcing. The Board does not believe it is necessary to mandate such a requirement in the ARC. Instead, the issue could be raised in future rate cases.

Could utilities be periodically asked to justify continued outsourcing?

The answer is yes. The Board has the discretion in future rate cases to decide it is reasonable to ask a utility to justify the prudence of continued outsourcing. For example, an upward trend in the affiliate's fully-allocated costs might trigger such a request.

6. Term of Contracts with Affiliates

a. Section 2.3.1: A maximum term is introduced

Under the proposed section 2.3.1, *the term of a contract between a utility and an affiliate shall not exceed five years.* The Board sees this as a light-handed way to require utilities to periodically review the terms of any affiliate outsourcing agreements to ensure the utility is paying a reasonable price in light of current conditions. The five year rule will apply whether or not a market exists for the outsourced good or service.

Where a market exists, new section 2.3.5 will provide that *before a utility renews a contract with an affiliate,* a fair and open competitive bidding process shall be used to establish the market price.

What are utilities expected to do at the end of an affiliate outsourcing contract?

At the end of the first contract with the affiliate, the Board's expectations of a utility are as follows:

- Where the transfer price was established under the cost-based rule, the utility should fully explore whether a market has developed for the outsourced item.
- Where the transfer price was established under the market-based rule, the utility should undertake another fair and open competitive bidding process.
- An automatic right to renew the contract will be inconsistent with the new ARC.

7. Transfer of Assets

a. Summary of changes

The Board proposes to replace the current section 2.3.4 of the ARC with a new transfer pricing rule that the transfer of assets from a utility to an affiliate should be at the higher of market price or net book value. The proposed amendments include a threshold below which market valuation is not required. They also include a requirement for an independent assessment of market price for more valuable assets. An ARC definition of "utility assets" is proposed.

b. Section 2.3.12: New way of pricing utility assets sold to affiliates

The ARC currently provides, in section 2.3.4, that "a utility shall sell assets to an affiliate at a price no less than the net book value of the asset". The merits of such a rule were questioned when the CRTC reviewed Bell Canada's transfer pricing policies (see Telecom Decision 86-17 at pages 60-62). For example, an intervenor suggested that "it is unfair to subscribers that assets be transferred at net book value when their sale in the marketplace could result in a greater return". [9]

In its decision, the CRTC eventually adopted the following rules:

> " Assets with a readily ascertainable fair market value, such as real estate and buildings, are to be transferred at that value. The Commission further

9 Federal competition officials had further concerns: "[An] advantage would accrue to a related competing company receiving an asset at less than fair market value in comparison to a non-related competing company which could be expected to pay full market value for the same asset."

directs where it is neither feasible nor practical to determine the fair market value of assets, as in the case of assets such as plant and equipment, the assets be transferred at net book value."

> **What are other regulators up to?**
>
> The NARUC Guidelines provide:
>
> Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value.

To address the above concerns, the Board proposes the following new general[10] rule:

If a utility sells or transfers to an affiliate a utility asset, the price shall be the greater of the market price or the net book value of the asset.

c. Section 2.3.13: A threshold is set for market valuation

The Board acknowledges it will not be cost-effective in all cases to require utilities to go to the expense of determining the market price of assets to be transferred. For this reason, it is proposed that depreciable assets of less than $10,000 NBV be transferable at NBV.

d. Sections 2.3.14/2.3.16: A requirement for an independent assessment is introduced

A review of North American best practices has underscored the importance of obtaining an independent assessment of the market price of assets sold between related parties. Such a measure is reasonable for the sale or purchase of more valuable assets between an utility and its affiliate.

The Board proposes a threshold based on the higher of a fixed dollar amount ($100,000) and a percentage test (0.1% of utility revenues, net of commodity costs). The effect of the fixed-dollar test is that small utilities will be required to provide an independent evaluation where the NBV of the asset sold to, or purchased from, its affiliate exceeds $100,000. The effect of the percentage test is that the largest utilities in the Province will not be required to obtain an independent evaluation unless the NBV of the asset transferred exceeds the $800,000 range.

e. Section 2.3.15: Assets sales from an affiliate to a utility are addressed

The Board proposes to introduce a new section dealing with asset sales from an affiliate

10 As discussed below, use of net book value is proposed for smaller transactions.

to a utility—the current rule does not have such a section:

> *If a utility purchases or obtains the transfer of an asset from an affiliate, the price shall be no more than the market price.*

The goal is to ensure utilities do not overpay for non-arms length purchases of assets from affiliates.

What other regulators are up to?

The NARUC Guidelines provide: “generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value”.

f. New definition of “utility assets”

The Board’s review of North American best practice revealed that some regulators explain what assets are covered by their transfer pricing rules (for a specific example, see the Maryland PSC’s July 2000 decision Re Affiliated Activities, Promotional Practices, and Codes of Conduct of Regulated Gas and Electric Companies). To provide greater guidance to stakeholders, the Board proposes to add to section 1.2 of the ARC the following definition:

> *Utility assets means tangible or intangible property included in the utility’s rate base.*

D. Discussion of relationship between transfer pricing and rate setting

1. General

The ARC governs the terms under which a utility can conduct business with an affiliated entity. More specifically, the transfer pricing rules regulate how much a utility should charge or pay when it does business with an affiliate. The question of how much of the transfer price the utility should be able to recover in rates is a separate question to be addressed at a rate hearing. The ARC does not bind the Board in the calculation of rates.

2. Proposed ARC amendments that are linked to rate setting

a. Section 1.3: The Board's ability to review prudence is confirmed

The Board proposes to add the following to the interpretations section of the ARC:

> *Nothing in this rule in any way limits the jurisdiction of the Board, in a proceeding under section 36 of the Act, to review the prudence of actions taken by a utility and determine what costs should be recovered by a utility through rates*.

While it may go without saying, these words are proposed to ensure all stakeholders understand the distinction between the transfer pricing rules and the subsequent rate setting process. As the Board has stated previously (see Enbridge 2002 test year decision, RP-2001-0032, at paragraph 5.11.14):

> [When] "calculating just and reasonable rates, subsection 36(1) of the Act specifically provides that the Board is not bound by the terms of any contract. While the contractual arrangements between [the utility] and its affiliates is evidence that may be of assistance to the Board, it is in no manner determinative of the amounts that will be included by the Board in the calculation of rates."

What are other regulators up to?

A U.S. state proposed adding a term to its affiliate relationship code providing that "conformance with these guidelines shall not preclude the Commission from evaluating the prudence of any transaction, investment, or expense" (section 8, Second Revised Cost Allocation and Affiliate Transaction Guidelines, Kentucky Public Service Commission, December 1999).

How will the Board balance its discretion with the desire for certainty?

The Board appreciates that stakeholders want some degree of regulatory certainty in this area. On the other hand, any given panel must exercise its discretion based on the facts presented in the case before it.

The Board will treat amounts paid to affiliates that were determined in full accordance with the ARC to be likely recoverable from rates.

However, where compliance with the spirit of the ARC is in doubt, the Board will rigorously scrutinize the appropriate rate treatment of the amounts paid by the utility. For example, the following instances will attract the Board's close attention for possible disallowance:

- If the utility tenders but chooses not to award the contract to the lowest bidder.
- If there is a failure to follow competitive bidding when a market exists.

b. Rates treatment of capital gains on asset sales to affiliates

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."[11]

The above is sometimes viewed as leading to differing treatment of depreciable versus non-depreciable assets: "The ratepayers have been paying for the cost of the building through depreciation charged as an operating expense each year and therefore should receive any gains or loss. … Conversely, ratepayers have not been paying depreciation on the sale of land and therefore, upon its sale, ratepayers are not responsible for any gain or loss on this non-depreciable item."[12]

What are other regulators up to?

For a summary of U.S. decisions, see Vol. 2, s. 40.04[5][d] of the American Gas Association publication "Regulation of the Gas Industry":

- With respect to depreciable property, payment of the depreciation expense by ratepayers has been regarded as creating an equity in the property that may justify giving ratepayers any gains upon its sale.
- Gains from the sale of nondepreciable property are allocated to shareholders.
- Special circumstances in connection with the use of the property have been deemed to make it equitable to give ratepayers the benefit of gains on property.

Another principle is that ratepayers have paid no more and no less than the service they have received from an asset (depreciable or non-depreciable), which would support ratepayers not receiving any capital gains.

Regulators have also been concerned about the incentives to be created by the rules adopted:

> "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 motivated to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred."[13]

11 See FCC Decision 87-305 at paragraph 112.
12 From OEB decision E.B.R.O. 399 re Northern and Central Gas Corp. Ltd. (1984) at page 145.
13 Alberta EUB Decision 2002-037 (March 21, 2002) at page 24. The OEB has also considered incentive effects: "This investment, while non-depreciable, was subject to interest charges and risk paid for through revenues and, until the gas manufacturing plant became obsolete, disposal of the land was not a feasible option. If, in such circumstances, the Board were to permit real estate profit to accrue to shareholders only, it would tend to encourage real estate speculation with utility capital. In the Board's opinion, the shareholders and ratepayers should share the

Regulators have been sensitive to the specific facts at hand, and this leads to differing results on a case-by-case basis. As the Alberta regulator has observed: "The Board notes in particular that in the U.S. decisions to which it was referred, as little as 50% of the gain and as much as 100% was allocated to customers".[14]

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.[15] As noted, many jurisdictions have considered whether or not the asset is depreciable to be a relevant factor in how to share the gain. The Board believes such a distinction could usefully guide how the issue is approached, but should not completely predetermine the actual results. The Board therefore proposes to offer the following interpretive guidance:

Rates treatment of capital gains on sale of utility assets to affiliates

Ratepayers should generally expect no less than 50% of the benefits from any capital gains on the disposition of depreciable utility assets to affiliates.

Utility shareholders should generally expect no less than 50% of the benefits from any capital gains on the disposition of non-depreciable utility assets to affiliates.

The precise sharing of benefits will be treated on a case-by-case basis.

c. Rates treatment of capital losses on asset sales to affiliates

Special concerns exist about the treatment of capital losses in affiliate transactions. As noted by the FCC (see paragraph 115, Decision 87-305):

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benefits of such capital gains." See E.B.R.O. 341 re The Consumers' Gas Company, 1976, at page 67.

14 Alberta EUB Decision 2000-41 (July 5, 2000) at page 27.

15 Similar views were reached by the B.C. regulator in a decision reviewing a sale of assets by West Kootenay Power Ltd.: "In these unique circumstances, the Commission determines that the customers are entitled to the difference between net book value and original cost. The Commission also determines that the remaining gains should be divided *equally* between customers and shareholders." See page 12, Decision G-112-01, dated October 26, 2001.

> "[Our] affiliate transactions rules do nothing to prevent ratepayers from taking a loss if assets are transferred out of regulation to a third party at less than net book value. Our rules do, however, prevent ratepayers from bearing a loss when the transaction is between affiliates. In case of affiliate transactions, incentives are likely to exist to manipulate the transfer price. In order to maximize overall corporate profits, a carrier could sell assets to its affiliates at below net book value, leaving the ratepayers to pick up the difference. The carrier simply does not have the incentive to minimize loss in a non-arm's length transaction."

The Board provides the following interpretive guidance to in this area:

Rates treatment of capital losses on sale of utility assets to affiliates

Ratepayers should generally expect to not assume responsibility for any capital losses on the disposition of utility assets to affiliates.

3. Non-pricing considerations when reviewing outsourcing in rate cases

The transfer pricing rules focus on setting a fair price in business dealings between utilities and affiliates. The Board also recognizes that outsourcing arrangements can have operational implications. These may be addressed in rate hearings.

Application of no-harm principle in rate cases

In rate cases, the Board may consider the operational implications of outsourcing arrangements, in addition to their cost consequences.

What other regulators are up to?

The Alberta regulator also recognized a role for non-financial considerations:

> "For a given asset transfer price, an assessment of harm to customers, including the current and future costs and benefits arising from the sale of the asset, and the operating implications thereof, will determine if the asset transfer price is sufficient to hold customers harmless over an appropriate period of time." (ATCO, 2003, page 81).

E. Discussion of affiliate information disclosure

1. Expanded information disclosure

To ensure that the new transfer pricing rules can be implemented most effectively, the Board proposes to expand the requirement of utilities to disclose information from their affiliates relating to outsourcing agreements.

a. Section 2.6.1.1(a): A new disclosure requirement is introduced into affiliate contracts

It is proposed that the following new section be added to the ARC:

> *A utility shall not enter into or renew a contract with an affiliate unless it contains provisions which require the affiliate to:*
>
> *(a) comply promptly with all requests by the Board for information with respect to:*
>
> *(i) the transactions provided for under the contract; and*
>
> *(ii) the cost to the affiliate of providing any service, resource or product under the contract;*

How does the Board currently get this information?

This new section will supplement the statutory powers the staff inspector already has to request access to an affiliate contract under section 107 of the *Ontario Energy Board Act*, 1998.

This requirement is a way to ensure the cost-based pricing rule can be scrutinized by the Board as part of its duty to approve just and reasonable distribution rates.

When will the Board want such information from affiliates?

The Board will be most interested in obtaining financial information when the cost-based pricing rule is used. Practically speaking, the Board will not need to request such information when a fair and open competitive bidding process has been properly followed since an objective market-based transfer price will have been adopted.

b. Section 2.6.1.1(b): A new disclosure requirement is introduced into affiliate subcontracts

The Board wishes to ensure that subcontracting by an affiliate will not have the effect of avoiding the overall intent of the ARC transfer pricing rules. As an initial step, the section requiring improved disclosure by affiliates will also apply where the affiliate subcontracts the work to another affiliate.

Concerns of other regulators.

In a North Carolina proceeding (see Duke Energy Fossil-Hydro, LLC, Docket No. E-7, Sub 694) the regulator expressed concern about the potential "to utilize multiple layers of affiliates in an attempt to increase the cost of goods or services to the utility".

How will the Board address any other issues around subcontracting?

If any other concerns emerge regarding the impact of large-scale subcontracting by affiliates, they will be addressed by the Board on a case-by-case basis in rate hearings.

How will the Board treat confidential information it obtains from affiliates?

The Board wishes to advise stakeholders that a Practice Direction is being prepared on the treatment of confidential information. It will apply to any information obtained from affiliates.

Is the definition of "affiliate" sufficiently broad?

The Board is aware that the most appropriate regulatory definition of an "affiliate" has been debated (as in the 2003 ATCO Decision). For rule-making purposes, "affiliate" is defined in the Act, but not for rate-making purposes. As part of its prudence review, the Board will pay close attention in rate hearings if the utility or affiliate outsources to a third-party who is not technically an affiliate of the utility but is still economically related to the same corporate group.

F. To whom will the ARC apply?

1. Section 1.4.2: ARC exemption introduced for non rate-regulated utilities

The Board proposes to apply the ARC transfer pricing rules to all utilities for which the Board sets rates.

The Board does not rate regulate two municipal utilities (Kingston and Kitchener), and some other very small entities. Transfer pricing rules are not relevant to the Board's regulatory goals in such instances. Accordingly, it is proposed the following exemption be added to section 1.4 of the ARC:

> *Section 2.3 of the Code does not apply to a utility that is exempt from rate regulation by the Board.*

Note utilities subject to the ARC can still apply for an exemption under section 1.6.

2. Application of new transfer pricing rules to electricity distributors to be determined

At present, the same transfer pricing rules are applied in both the natural gas and electricity sectors. The proposed amendments are intended to be incorporated into the natural gas ARC only. The Board will decide later whether similar amendments should be made to the electricity ARC. If so, Article 340 (Application of Accounting Concepts: Allocation of Costs and Transfer Pricing) of the Accounting Procedures Handbook for Electric Distribution Utilities may also be reviewed.