Report
on

The Disposition Of Tax Savings On Disallowed Expenses

Submitted on behalf of

THE
COALITION OF ISSUE THREE DISTRIBUTORS

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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. UNDERPINNING REGULATORY PRINCIPLES AND GOVERNMENTAL OBJECTIVES

A. The "Benefits Follow Costs" Principle

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*).

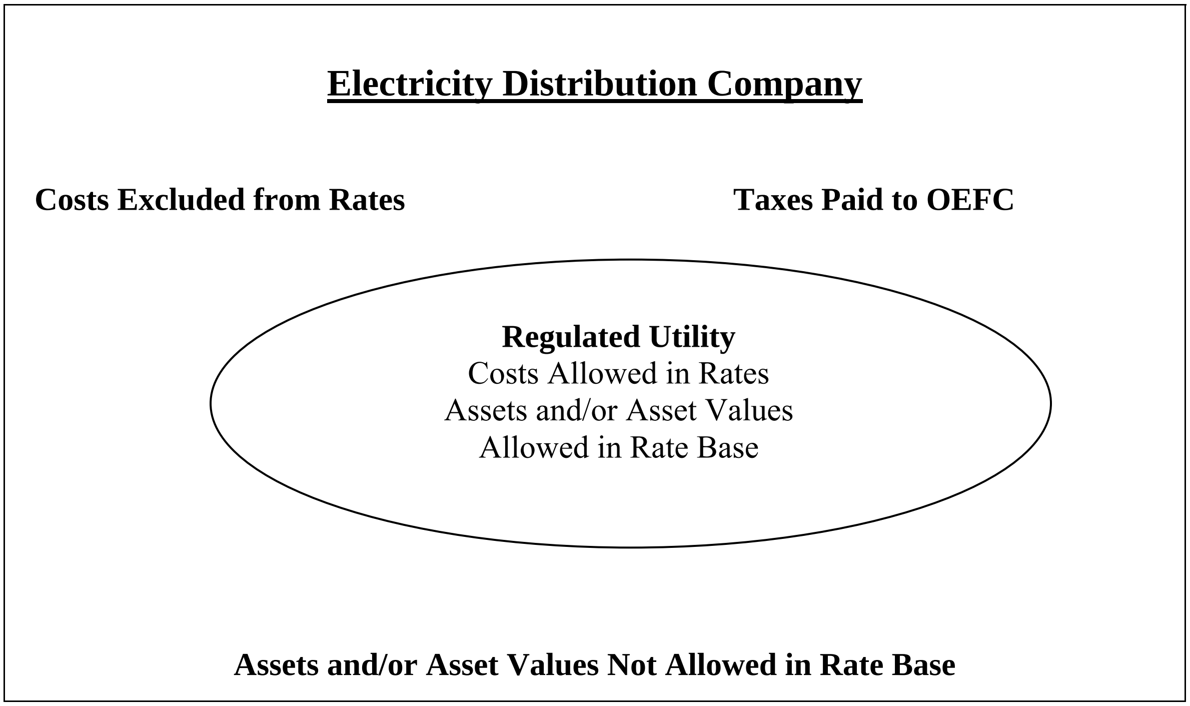
19. Stated another way, expenditure and investment decisions for unregulated competitive enterprises assume a sharing of risks between shareholders (the after-tax portion) and governments (the tax portion). Flowing through the tax savings that arise from utility costs that have been disallowed for ratemaking 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. 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. 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. 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." (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 same 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. <u>RESPONSE TO EVIDENCE OF DR. MINTZ</u>

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 costs 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).