THE PUBLIC UTILITIES BOARD

FOR THE PROVINCE OF ALBERTA

DECISION NO.: C78221

FILE NO.: E4.512.2

THURSDAY, THE TWENTY-FIRST DAY OF DECEMBER, A.D. 1978

IN THE MATTER OF "The Alberta Gas Trunk Line Company Act", being Chapter 37 of the Statutes of Alberta, 1954, as amended;

AND IN THE MATTER OF "The Public Utilities Board Act", being Chapter 302 of the Revised Statutes of Alberta, 1970, as amended;

AND IN THE MATTER OF complaints in writing in respect to the rates, tolls or charges fixed and charged by The Alberta Gas Trunk Line Company Limited and in particular the fixing and charging an annual rate of return on rate base of 10 3/4% effective December 1, 1977.

BEFORE:

THE PUBLIC UTILITIES BOARD FOR THE PROVINCE OF ALBERTA

2

3. DETERMINATION OF A FAIR RATE OF RETURN ON RATE BASE (Continued)

> the Board, as it is no doubt aware, that the assessment of Alberta Gas Trunk's rates must involve other considerations than would normally bear on the assessment of rates for the conventional distributor."

4. SEVEN ISSUES TO BE CONSIDERED

AGTL dealt with seven issues which it considered "germane to the complaint" in the following sequence: Diversification, Appropriate Capital Structure, Financing, Capital Requirements, Treatment of Deferred Taxes, Risk and The Appropriate Rate of Return on Common Equity..." The issues will be dealt with by the Board in that sequence.

(a) Diversification

(1) AGTL's Position

AGTL's position in respect to Diversification is set out at page 1 of Tab 3 of its final argument as follows:

> "Much time during the proceeding was devoted to an exploration of Alberta Gas Trunk's interests in business outside of its Alberta Gas Transmission service - so called diversification. In the main, the bulk of these activities have been undertaken to the benefit of the producers who, to this date, have had to absorb none of the risks nor pay any additional costs of

3

Public Utilities Board, Alberta
DECISION NO.: C78221

4. SEVEN ISSUES TO BE CONSIDERED (Continued)

(a) Diversification (Continued)

(1) AGTL's Position (Continued)

such diversification. In short, there has been no adverse impact whatsoever on the producers. On balance, Alberta Gas Trunk's shareholders have assumed the risks whilst Alberta producers benefit."

(2) The Complainants' Position

The Complainants' position with respect to diversification was specifically dealt with in the Producers' Argument at page 51 as follows:

"On page 1 under Tab 3 the suggestion is made that the bulk of AGTL's diversification activities have been undertaken to the benefit of the producers followed by quotations from Mr. Pierce's evidence. Even if these activities have benefited the producers, they have presumably been undertaken for the benefit of AGTL's shareholders who will reap the gains or bear the losses as the case may be. Any incidental benefits to the producers have no bearing whatsoever on the matter to be determined by the Board in these proceedings, i.e. the just and reasonable rate of return to be allowed to AGTL in its gas transmission business."

(3) Conclusions of the Board

The Board agrees with the Producers' position that the matter to be determined by the Board in these proceedings is "the just and reasonable rate of return to be allowed to AGTL in its gas transmission business." (underlining added)

4

4. SEVEN ISSUES TO BE CONSIDERED (Continued)

(a) Diversification (Continued)

(3) Conclusions of the Board (Continued)

From the evidence adduced and from the observations of the Board as to AGTL's program of diversification, it appears that the overall cost of capital to AGTL has not been adversely affected by such activities. No evidence was produced to quantify any beneficial effect on AGTL's overall cost of capital or to recommend how such beneficial effects,if any, should be allocated between the Alberta cost of service gas transmission business and its other activities.

(b) Appropriate Capital Structure

(1) AGTL's Position

AGTL set out its position with regard to this issue on pages 11 and 12 of its Final Argument, as follows:

> "In examining the projection of capital requirements for the year 1978,it became apparent that the common share equity expected to be outstanding during the period was significantly in excess of the common share equity that was anticipated at November 1, 1975 when the rate of return on rate base was increased to 10.375%.
>
> In particular, Schedule 501, Tab 5,Volume 1(Exhibit 2) shows that the projected common equity for the forecast period to October 31, 1978 would average $291.6 million (or 43.6% of the total capitalization) vs. $163.5 million (or 26.59% of total capitalization) projected for the forecast period commencing November 1,1975.

NATIONAL ENERGY BOARD

REASONS FOR DECISION

In the Matter of the Application Under
Part IV of the National Energy Board Act
(Rates Application)

OF

TRANSCANADA PIPELINES LIMITED

August 1980

Ce rapport est publié
séparément dans les
deux langues officielles.

6

CHAPTER 3

RATE OF RETURN

DEEMED CAPITAL STRUCTURE

In its current application, unlike previous years where exclusive reliance was placed upon the use of actual consolidated capital structures, TransCanada submitted that a deemed capitalization should form the basis for the determination of its rate of return on rate base.

The applied-for capitalization, in conjunction with its individual and overall requested rates of return, is shown below.(1)

Deemed Average Capitalization for the Test Year Ending 31 July 1981

	Amount ($000)	Ratio %	Cost Rate %	Cost Component %
Debt - Funded	677 440	46.03	8.43	3.88
- Unfunded	229 366	15.59	13.00	2.03
Total Debt Capital	906 806	61.62	9.59	5.91
Preferred Share Capital	85 989	5.84	7.36	.43
Common Equity	478 783	32.54	16.00	5.21
	1 471 578	100.00		11.55

(1) In keeping with the Board's 1979 TransCanada Rate Decision, the Company excluded debt arising from its "take or pay" obligations under its gas purchase contracts.

The evidence presented indicated that the deemed capital structure approach was adopted by TransCanada as a result of the large-scale diversification program it had recently embarked upon. As it recognized that this program involves the financing of investments possessing risk characteristics significantly different from those of its utility business, TransCanada considered that it could no longer employ its consolidated capital structure for rate-making purposes. Rather, it proposed a deemed capital structure which was equal to the sum of its inside- and outside-Alberta rate bases and which possessed debt/equity characteristics essentially consistent with the Company's view of the business risks of its pipeline operations. TransCanada submitted that its approach effectively insulated the ratepayers from the costs of financing its diversification and was, therefore, supportive of its request that an amount of income tax be collected in the cost of service which would have no relation to the income tax effects of its diversification.(1)

The Board agrees that the Company's applied-for deemed capital structure serves to insulate the ratepayers from the capital costs associated with its diversification program, and considers it as efficient as might be hoped for by ratepayers in terms of a pre-tax cost of capital. The Board, therefore, approves the use of a deemed capital structure.

---

(1) See Chapter 4 - Allowable Cost of Service, Income Taxes.

8

The Board has noted the concerns expressed by intervenors that the ratepayers continue to be insulated from the capital costs of diversification. The onus will be on the Company to demonstrate over time that this objective has been met.

The composition of the applied-for capital structure, together with the various individual cost rates, is discussed below.

FUNDED DEBT

The funded debt component of the deemed capital structure incorporates all of the Company's existing first mortgage pipeline bonds, sinking fund debentures, and subordinated debentures. This debt is of a relatively lower cost, due to its historical nature, and is unassociated with the Company's current diversification program.

The computation of the imbedded cost rate of this debt is shown in Appendix V of this decision. This cost rate has been computed in a manner consistent with that used in the 1979 proceeding and was not at issue in the current hearing. Accordingly, the Board accepts the applied-for cost rate of 8.43 percent.

UNFUNDED DEBT

As mentioned previously, total capitalization is set equal to the total of the Company's inside- and outside-Alberta rate bases. The unfunded debt component of this capital

9

CANADA

NATIONAL ENERGY BOARD
REASONS FOR DECISION

In the Matter of the Application Under
Part IV of the National Energy Board Act
(Tolls Application)

of

WESTCOAST TRANSMISSION COMPANY LIMITED

AUGUST 1983

CHAPTER 7

Rate of Return

Westcoast applied for the following deemed capitalization and before-tax rate of return on rate base for the test year ending 31 December 1983.

TABLE 7-1

	Amount ($000)	Ratio (%)	Cost (%)	Return Component (%)
Balance of External Financing	25,895	3.34	12.97	.43
Long-Term Debt	445,157	57.49	10.80	6.21
Preferred Shares	32,273	4.17	8.50	.35
Common Equity	271,021	35.00	15.90	5.57
	774,346	100.00		
Rate of Return on Rate Base after Income Taxes				12.56
Utility Normalized Income Taxes			6.46	
Rate of Return on Rate Base before Income Taxes				19.02

7.1 Deemed Capital Structure

The applied-for capital structure reflects the capital allocation method set out in the Board's November 1980 Decision which was established in order to ensure that the ratepayer did not subsidize non-utility investments. Accordingly, the average test-year utility capitalization was equated to the average rate base plus construction work in progress. The common equity component was deemed to comprise 35 percent of this average capitalization. The remainder of the capitalization was deemed to consist of long-term debt, preferred equity and balance of external financing capital in the same proportions as each is represented in the total amount of long-term debt, preferred equity and balance of external financing capital existing within the corporation. The individual components of the capitalization together with matters relating to the associated capital cost rates are discussed below.

7.2 Balance of External Financing

The term "balance of external financing" refers to debt which the Company has yet to fund on a long-term basis for the 1983 test year. The Company requested that this balance be costed at a long-term rate of 12.97 percent on the assumption that it will be funded on a long-term basis during 1983. However, during cross-examination, it was determined that WTCL has no plans for further long-term issues in 1983 and that it is likely that this balance will continue to be financed during the test year on a short-term basis. It was also determined that corporate policy is to obtain short-term funds from the least cost source, which was stated, in general,to be the commercial paper market. The Company's recently experienced monthly short-term borrowing rates were given in evidence. The Board notes these rates averaged 121 basis points less than the average commercial bank prime rate of 11.69 percent for the first four months of 1983.

BCPC was the sole intervenor to take issue with the Company's proposal for costing the balance of external financing. Its expert witness suggested a long-term rate was inappropriate as Westcoast had already financed this balance for a significant portion of the test year at short-term rates. This witness proposed using a combined short-term/long-term rate of 11.89 percent to cost the balance of external financing. This rate was based on the average commercial bank prime rate for the first four months of 1983 and an estimated long-term rate of 12.00 percent for the balance of the test year.

7.3 Long-term Debt

Westcoast calculated its embedded test year cost of long-term debt to be 10.80 percent and allocated 87.3 percent of its total debt to the utility operation, based on the allocation method set out in the Board's November 1980 Decision. While no intervenor contested Westcoast's estimated embedded cost of long-term debt, CPA/IPAC took issue with the method of allocating long-term debt between utility and non-utility operations.

THE PUBLIC UTILITIES BOARD, ALBERTA

DECISION E93060

re:

NOVA CORPORATION OF ALBERTA

In the matter of a complaint by the Canadian Association of Petroleum Producers that the rates, tolls or charges for customers of the Alberta Gas Transmission Division of NOVA Corporation of Alberta for the calendar year 1993 are not just and reasonable.

BEFORE:

N. W. MacDonald	Presiding Member
T. D. Hetherington, Q.C.	Member
T. C. Roberts	Member

FILE 8525-4

August 20, 1993

3. MANNER OF DETERMINING JUST AND REASONABLE TOLLS

The NOVA Act, Section 37(2), provides as follows:

> "(2) On complaint in writing of an interested party, the Public Utilities Board may, or on the direction of the Lieutenant Governor in Council shall, after notice to and hearing of the parties interested, determine the justness and reasonableness of the rates, tolls or other charges fixed or varied by Nova and by order in writing may vary or confirm the rates, tolls or other charges."

Unlike the PUB Act and the *Gas Utilities Act*, the NOVA statute is silent as to the factors to be considered by the Board in assessing the justness and reasonableness of AGTD's tolls.

The Board's 1978 determination on the appropriate treatment of income tax by the AGTD was appealed to the Court of Appeal and then to the Supreme Court of Canada. In *Alberta Gas Trunk Line Company Limited* vs. *Amoco Petroleum Corporation* (1980 3WWR 1, 13) Mr. Justice Clement of the Court of Appeal reviewed the legislation and concluded as follows:

> "With all this, it is not to be taken that the legislature intended that the Board should not follow well established concepts and methods, but should devise for the exercise of its jurisdiction under the *AGTL ACT* some different precepts and principles. It would be unreasonable to come to such conclusion."

The Board, in accordance with such well established concepts and methods, has in previous Decisions determined that AGTD should be allowed to earn a fair return on its rate base on a stand alone basis.

13

3. MANNER OF DETERMINING JUST AND REASONABLE TOLLS

In Decision E92086 dated October 26, 1992, the Board recognized that NOVA is not a pure utility operation and that NOVA's non-AGTD operations include diversified activities with dissimilar business risks to those of AGTD. Accordingly, the Board considered that the components of AGTD's capital structure and the cost factor for each component should be determined on a stand alone basis consistent with its business risk and its ability to attract capital on reasonable terms.

The Board notes that the amount of the AGTD rate base has been agreed upon by the parties and is not an issue before the Board in 1993.

Accordingly, the Board has proceeded on the assumption that the rate base has been determined substantially in accordance with well established regulatory concepts and methods.

With respect to fair return, the Board considers that the stand alone principle requires the fixing of an appropriate capital structure for AGTD in the light of its business risk and financial circumstances and the determination of stand alone cost rates for each of the components of the capital structure.

14

5. MANNER OF DETERMINING JUST AND REASONABLE TOLLS

While endorsing the stand alone principle, the Board also stated in Decision E92086 that inquiry into non utility operations would be relevant to ensure that the following criteria are being satisfied:

(1) The financial integrity of NOVA is not being threatened in a way that will result in cessation of safety or service provided by AGTD.

(2) The AGTD customers are not subsidizing the non-AGTD operation of NOVA.

The Board notes that as long as AGTD remains consolidated with NOVA's chemical and other operations, NOVA, AGTD's customers and the Board (when called upon by complaint) will be required to face the contentious issue of whether or not the corporate diversification of NOVA has placed additional financing and/or other costs on AGTD's operations.

The Board also notes this is the second year in a row that a complaint has been lodged respecting AGTD's rates, tolls or charges. The Board remains available to resolve such complaints, however, the Board is hopeful that NOVA and its customers can, in future years, arrive at mutually beneficial negotiated rates, tolls or charges on the basis of the principles determined and established by the Board in this Decision and in Decision E92086.

The Consultants then investigated whether allowed ROEs in the neighborhood of 8.00%, in combination with a deemed and actual CER of 40%, would pose a significant threat to the financial integrity of OHSC's Transco and Disco business units or undermine their chances of being accorded "A" ratings on their future debt issues. Based on discussions with the utility analysts at the DBRS and CBRS rating agencies concerning electric distribution utilities in various risk classes, the Consultants concluded that, considering OHSC's large size, its low business risk, its more-than-ample 40% common equity ratio, and its interest coverage ratio ("ICR") at an 8.0% ROE, OHSC's financial integrity on a stand-alone basis, and an "A" rating or better for its debt would be assured if the Board were to allow OHSC's regulated transmission and distribution businesses to earn ROEs in the 8.00% to 8.25% range.

POSITIONS OF THE PARTIES

OHSC was concerned with the business risk analysis presented by the Consultants and their resulting conclusions regarding both: a) the comparative business risk associated with electricity and gas utilities; and b) the degree of business risk currently faced by OHSC compared to other electric utilities. OHSC also had concerns about the tests employed and the external confirmations cited by the Consultants regarding whether OHSC could readily receive an "A" rating.

OHSC felt the Consultants understated O&M and capital risks attributable to electric utilities relative to gas and erred in concluding that gas LDCs are exposed to greater revenue forecasting risk. OHSC stated that the threat from self-generation is real and that while open access will improve the competitiveness of electricity, it will also increase uncertainty.

With respect to OHSC's business risk relative to that of other electric utilities and the sample of gas/electric utilities employed by the Consultants in their analysis, OHSC contended that the Consultants misinterpreted MDC's recommendations, failed to acknowledge regulatory risks associated with OHSC's future, inappropriately focused on the near term and Government ownership of OHSC, and misread the status and overall purpose of OHSC's asset condition assessments and work plans. In addition, OHSC observed apparent inconsistencies in the derivation of the Consultants' conclusions.

While acknowledging that OHSC's capital structure and target credit rating were mandated, Energy Probe believed some sensitivity analysis should be conducted to determine, from a ratepayer's perspective, the optimal capital structure, resulting credit rating, and cost of debt and equity. With respect to ROE, Energy Probe noted that in reference to a peer group of regulated utilities, OHSC's proposal results in a higher rate of return than can be justified by first principles. Energy Probe suggested that, given OHSC's low debt to equity ratio relative to Ontario gas utilities, which implies a reduced overall risk, OHSC's ROE should be 9%.

AMPCO recommended that the return for OHSC not exceed 8.0% and found the information submitted by the Board Staff's Consultants to be more "persuasive" than that submitted by Ms. McShane. AMPCO noted that the quantitative results are sensitive to the data chosen. AMPCO found that the Consultants' selection of analytical models to be more methodical and relevant. AMPCO disputed OHSC's suggestion that it faces long-run business risk and suggested that this is an attempt to exaggerate the risk premium included in the ROE. AMPCO also believed OHSC's arguments regarding asset impairment were ill-founded. With respect to PBR, AMPCO did not believe it created additional risk and instead would be favorable for regulated entities. Finally, AMPCO did not attribute risk to uncertainty in the MDC proposals.

PWU suggested OHSC's ROE is reasonable and indicated that in its view the Consultants misapplied the "stand-alone" principle in that the "newness" of OHSC was not considered as a risk factor for investors. In particular, PWU stated that the Consultants discounted the "newness" factor in that they did not foresee any imminent sale of equity interest, and, at such time, they believed such newness issues would be resolved, and, as such, investors

17

Board Findings

CAPITAL STRUCTURE AND COST OF DEBT

The Board accepts a capital structure target of 60% debt and 40% equity and the dual requirements of achieving an "A" credit rating and maintaining its financial integrity on a stand-alone basis. The Board accepts the embedded long-term debt rate and the amount of long-debt proposed by OHSC for inclusion in its capital structure. The Board has adjusted the long-term debt component to balance total capital with rate base. The Board has attributed OHSC's forecast incremental long-term debt refinancing costs to the long-term debt adjustment component, as these funds may conceivably reduce OHSC's capital requirements. Based on OHSC's forecast, the Board has used a rate of 6.3% for 1999 and 6.1% for 2000.

ROE ANALYSIS METHODOLOGY

With regard to the analytical models used to determine the appropriate ROE, OHSC has stated that the Board should set an initial ROE using a broad-based approach, by reference to multiple tests. Moreover, OHSC submitted that it is not necessary that each test employed to set a benchmark return be one that can be used in some subsequent formulaic return methodology. The Board considers it unlikely, due to cost and workload considerations, that a broad-based approach using multiple tests will be used to establish the ROE for each of Ontario's electric distribution utilities in the future. The Board is of the view that other electric distribution utilities should be afforded similar regulatory treatment as OHSC, to the extent practical, to level the playing field. Therefore, the Board does see merit in applying analytical tests that produce results consistent with formulaic methodologies, such as the ERP test. In addition, as regulatory symmetry between gas and electric utilities is desirable, it follows that consistency and symmetry between the analytical techniques used to establish OHSC's and Ontario gas utilities' allowed returns is also desirable. The Board's formulaic rate of return methodology is based on an ERP

18

ASPECTS OF UTILITY-SPECIFIC RISK

The Board has reviewed the data, information, and discussions put forth by Ms. McShane and the Consultants regarding the various utility-specific risk factors that should be acknowledged in the course of the ROE determination for OHSC. The Board has also reviewed the submissions of OHSC and other interested parties regarding risk assessment.

The risk factors in dispute include:

1) capital and O&M risks attributable to facilities;
2) revenue forecasting risk;
3) long-term versus short-term outlook;
4) Government ownership in relation to a "stand-alone" ROE determination;
5) the implications of the asset condition assessments and current work plans;
6) conclusions with respect to the MDC recommendations and the treatment of by-pass;
7) the assessment of regulatory risk; and
8) the impact of OHSC's status as a new entity.

The Board has carefully reviewed the positions of all parties regarding the impact of the above risk factors on OHSC. The Board finds merit in many of the arguments but also that many are of questionable basis. On balance, the Board finds that there is a reasonable doubt and uncertainty related to the relative business risk of OHSC as compared to other electric utilities and the two major gas utilities in Ontario. There are numerous factors that increase the business risk of OHSC, and, a similar number of offsetting factors. The Board notes that it is difficult to assess many of the factors given that OHSC does not have a track record. Indeed, absent such a track record it is difficult to draw definitive conclusions regarding OHSC's business risk or that of its separate business units. The Board finds that until OHSC has a track record, it is prudent to assess OHSC's basic business risk as being approximately equivalent to other major Canadian electric utilities, major gas pipelines, and Ontario gas utilities. Accordingly, the Board finds that the downward adjustment that has been reflected in the Consultants' ERP should be removed. While the available evidence with respect to the magnitude of this adjustment is open to debate, the Board estimates the amount to be approximately 50 basis points. Therefore, the Board concludes that an appropriate "all-in" ERP at a forecast long-term debt rate of 5.37% is 350-375 basis points. Thus, adding the risk premium to the forecasted bond rate yields an ROE for OHSC of between 8.87-9.12%. For purposes of determining the revenue requirement for OHSC, the Board will use a ROE of 9.0%.

The Board's guidelines on the determination of the rate of return on common equity stipulate the method by which such allowed return is adjusted to reflect changes in long term interest rates. For 2000, the rate of return on common equity shall be adjusted using the method stipulated in the Board's guidelines and December 1999 interest rate data.

The Board believes its findings are consistent with the goal of achieving an "A" credit rating. The Board notes that, based on purely quantitative data in OHSC's application, the Consultants concluded that an "A" credit rating would be achieved. In addition, the Board notes that OHSC's coverage ratio is significantly higher than that for the Ontario natural gas utilities, which have coverage ratios below 2.5. The Board agrees with OHSC that rating agencies do not evaluate bond ratings by "raw" numbers alone but also employ qualitative factors. The Board's upward adjustments and overall finding should provide a sufficient cushion to address the qualitative concerns of credit rating agencies.

The Board also compared its finding relative to returns allowed for gas utilities in Ontario. Currently, rates for Ontario's gas utilities are slightly higher than those recommended by the Board for OHSC. Specifically, the rate for Enbridge Consumers Gas and Union Gas is 9.51% (effective October 1, 1998) and 9.61% (effective January 1, 1999), respectively. These rates of return on common equity are subject to adjustment to reflect changes in the forecast debt rate data prevailing at the time the Board issues its decision regarding rate applications made by these utilities. Enbridge Consumers Gas has an application before

20

the Board for new rates effective October 1, 1999, and Union Gas has an application before the Board for new rates effective January 1, 2000.

At the time the ROEs for the gas utilities were set, the long Canadian bond rates were 5.73% and 5.66% for Enbridge Consumers Gas and Union Gas, respectively. Thus, the effective risk premium applied to these two major gas utilities was 378 and 395 basis points, respectively. Using the 5.37% forecast long Canada bond yield, application of the Board's guidelines would produce an effective premium of 387 basis points for Enbridge Consumers Gas and 402 basis points for Union Gas. The effective risk premium recommended for OHSC of 363 basis points lies slightly below the levels of Enbridge Consumers Gas and Union Gas. However, both major gas utilities have capital structures with 35% CERs while that for OHSC is 40%, which justifies a lower risk premium to account for differences in financial risk.

In addition to comparing the Board's finding with the allowed returns of Ontario gas utilities, one can make a broader comparison with natural gas pipelines in Canada. Specifically, the all-in risk premium for OHSC is comparable to that applied to natural gas pipelines in Canada. In its March 5, 1995 Reason for Decision (RH-2-94) the National Energy Board ("NEB") found that an all-inclusive risk premium of 300 basis points as appropriate, based on a long-term Canadian bond yield of 9.25%, for TransCanada Pipelines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Ltd., Trans Quebec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd., and Trans-Northern Pipeline Inc. Moreover, with the exception of one pipeline (Trans Mountain Pipe Line Company), the NEB found capital structures ranging from 30-35% common equity to be appropriate. The NEB, however, provided for an adjustment mechanism to reflect changing bond rates. The ROE would change by 75 basis points for every 100 basis points change in the long term bond rates. Thus, if adjusted to reflect today's long term bond yield contained in the Board's formulaic approach, 5.37%, the risk premium would be 397 basis points. Although the ERP recommended for OHSC is somewhat lower, it is nonetheless justified given the higher CER for OHSC relative to the

21

NEB pipelines. Thus, the Board concludes that its risk premium finding is reasonable in comparison to the findings determined by the NEB.

22

RP-1999-0034

IN THE MATTER OF a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors.

BEFORE: George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member

DECISION WITH REASONS

January 18, 2000

where the utility believes it is necessary to retain such a provision in order to mitigate the rate impact on customers. However, any such requests must reflect the separation of distribution rates from cost of power. The Board expects that the need to have a minimum bill provision in a two-part rate structure will be reviewed for second generation PBR.

Unbundling and Rate Design Model

3.2.29 Appendix A of the draft Rate Handbook includes an illustration of the unbundling and rate design methodologies proposed by Board staff.

3.2.30 The availability of a spreadsheet model for unbundling and rate design could be of assistance to utilities in developing their proposed initial rates. In that regard, the Board understands Board staff are already in the process of developing such a model. The Board expects Board staff to ensure that the model reflects the Board's findings in this Decision, including the Board's concerns regarding rate impact.

3.3 ADJUSTMENTS TO UTILITY REVENUE REQUIREMENT

3.3.1 In establishing initial rates, the draft Rate Handbook stipulates that certain adjustments to current rates may be warranted, such as an allowance for market-based returns, which includes payment in lieu of income taxes, or proxy taxes, and for prudently incurred costs associated with the transition to the new market structure.

Market-based Return

3.3.2 The draft Rate Handbook proposes that distribution utilities would fall into four categories for the purpose of establishing a deemed capital structure. The draft Rate Handbook identified four levels of risk classification based on rate base size.

3.3.3 In order to calculate the market-based return, a rate base has to be determined. The total rate base equals total deemed capitalization of the utility. The cost associated with the debt component of the deemed capital structure is included in

24

the draft Rate Handbook as part of the market-based rate of return revenue requirement ("MBRR") formula. The cost rate associated with the common equity component that was used in the draft Rate Handbook was 9.75 percent. The illustrative values for the cost of debt and common equity were based on a forecast that long-term Canada bond yields would average between 5.95 percent and 6.0 percent during year 2000, implying an equity risk premium of 375-380 basis points.

3.3.4 The methodology for determining the initial rate of return on common equity and the annual setting of Return on Common Equity ("ROE") is based on the methodology used by the Board in regulating natural gas utilities and was also applied in setting the transitional rates for OHSC (RP-1998-0001). The actual values of both the debt rate and the return on common equity will be calculated by the Board using data from December 1999.

3.3.5 The Board notes that certain parties submitted that the implied equity risk premium that underpins the 9.75 percent[9] rate of return used in the draft Rate Handbook is inadequate. The Board has not been persuaded that the implied equity risk premium contained in the 9.75 percent proposal is unreasonable. In finding so, the Board has considered the authorized rates of return for the gas utilities in Ontario as well as the authorized rate of return for OHSC. As for the argument by Enbridge Consumers that the single risk premium may not adequately compensate the higher risk faced by a smaller electric utility, the Board notes that the differentiation in the capital structure contained in the draft Rate Handbook based on rate base size makes allowance for the perceived differences in risk.

3.3.6 To determine the level of return, an initial rate base must be established. Such rate base must be related to the "wires only" activities. The Board is aware that some distribution utilities have already been incorporated and therefore have

---

[9] The updated rate of return on common equity to be used in establishing the initial rates may change to reflect the forecast values of the long-term Canada bond yields based on data for December 1999.

established their "wires only" activities, others have not. In either case the Board needs the information to establish the "wires only" rate base.

3.3.7 If the utility has undergone incorporation and separation of regulated and competitive activities when an application for initial rates is filed, the establishment of the utility rate base will be reviewed by the Board to ensure that there is compliance with the Board's guidelines with regard to the definition of distribution activities. If incorporation is not completed at the time of filing, a proforma projection should be prepared. In either case, the utility must present the rate base both before and after separation. The amounts removed from the integrated rate base, actual or notional, should be based on net book value.

3.3.8 In order for the Board to determine the adjustment required to reflect a market return on rate base, the Board requires information on the return achieved. The Board has determined that it would be appropriate to use year end 1999 data for determining the initial rate base.

3.3.9 In comparing the after-tax market return in establishing the initial rates with the achieved 1999 return, the Board's implicit assumption is that the integrated utility earned the same rate of return on all its business activities. The Board recognizes that there may have been differences in the contribution of different activities to the overall return but, in light of the complexities and substantial effort and time required to address such matters, the Board has determined that this assumption is reasonable in order for the distribution systems to be able to have initial rates in place before market opening.

3.3.10 The Board is cognizant of the fact that in the absence of shareholders, and through the previous regulator's cap on working capital levels, many of the municipally-owned electricity distribution utilities have historically earned below market-based returns. Upon corporatization, with the municipalities as their shareholders, the distribution utilities may wish to propose rates to target returns up to the allowable MBRR. Under this scenario, the Board is concerned with the resulting rate impacts in the establishment of the initial rates.

3.3.11 Throughout this proceeding the Board has heard from intervenors that ratemaking should as much as possible be a local decision. The Board agrees. The decision to implement full MBRR for all components of the rate base is a decision that falls upon the management, directors and the shareholders of the local utility, and the Board will require the utility to inform and explain the rate changes to their customers as well as the reasons thereof.

3.3.12 Based on the report of the distribution rates task force, implementation of a market-based return and taxes may result in an average increase on revenue required for distribution and cost of power of 6.1 percent. The revenue requirement for some utilities would be lower than that under the existing rates. For the majority of utilities the revenue requirement would be higher. In order to mitigate rate impact in the implementation of the initial rates, the draft Rate Handbook proposes that a deferral mechanism be put in place. Subject to the Board's findings later in this chapter that the initial rates will not incorporate any transition costs, the Board accepts the deferral mechanism proposal in the draft Rate Handbook.

3.3.13 Given the flexibility afforded to the utilities through the deferral mechanism, the Board will expect the utilities to take advantage of that flexibility and to propose initial rates that will not result in undue rate impacts. In its review of rate proposals and under its authority to fix rates, the Board will either seek revised proposals or fix the rates itself should it be found that rate impacts have not been adequately addressed.

Treatment of Contributed Capital

3.3.14 The draft Rate Handbook stipulates that:

> *Contributed capital collected under Ontario Hydro's regulatory regime and currently included in rate base will remain in rate base. The distributors will continue to earn a return on the contributed capital portion of the existing rate base until these assets are fully depreciated. However, the rate of return that will be applied to this component of the*

EB-2005-0421

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

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited pursuant to section 78 of the *Ontario Energy Board Act, 1998* for an order or orders approving or fixing just and reasonable rates for the distribution of electricity, to be implemented on May 1, 2006.

BEFORE: Gordon E. Kaiser
Vice Chair, Presiding Member

Ken Quesnelle
Member

Cathy Spoel
Member

DECISION WITH REASONS

April 12, 2006

5. CAPITALIZATION AND COST OF CAPITAL

5.1 CAPITAL STRUCTURE

5.1.1 In this application, Toronto Hydro uses the deemed capital structure of 35% equity and 65% debt as set out in the Rate Handbook. None of the intervenors object. In the absence of any evidence or argument to the contrary the Board sees no reason to deviate from the Handbook position.

5.2 RETURN ON EQUITY

5.2.1 The Applicant seeks a return on equity of 9%, and claims it is entitled to that rate because that is the rate defined in the Electricity Distribution Rate Handbook. The Applicant argued earlier in these proceedings that this rate could not be contested for the same reason; it was entitled to rely upon the Handbook amount.

5.2.2 The Applicant brought a Motion on January 16, 2006 seeking a ruling on this issue. The Board held that the Handbook was intended for those applicants that were filing on a historical year basis.[4] The Board did, however, find that where the issue was not contested and where there was no contrary evidence, the Handbook values could be relied upon by utilities filing on a forward year basis[5].

5.2.3 However, that is not the case here. This is a contested issue. The Board staff and others have proposed a mechanistic update based on updating the long Canada bond rate. Where an applicant files on a forward test year basis it proposes current data as opposed to outdated data. It does that, of course, for those items where its costs have increased, in order that it might recover those costs. It becomes a problem if the utility can unilaterally determine which of the costs should be updated. As the Board stated in its Decision on the Motion:

---

[4] EB-2005-0421, transcript Volume I, p. 113 - 123
[5] Transcript, pp. 118-119

"it is not unreasonable to assume that with respect to those variables, where automatic, simple updating can be implemented, that should be accomplished as opposed to sticking with outdated '04 data when that's not necessary."

5.2.4 In this case new data has been presented by Board staff. Updating the return on equity based upon current data with respect to the long bond rates yields a return on equity of 8.36% as opposed to 9%. This results in a reduction of the revenue requirement of approximately $3.5 million.

5.2.5 This does not account for any change in the equity risk premium, which is the other component. The Applicant argued that if the return on equity is to be updated to reflect a current long Canada bond rate then the equity risk premium should be updated in the manner proposed by Ms. McShane[6]. That results in a return on equity of 8.65%. The Board believes that both adjustments are legitimate updates.

5.2.6 However, other matters intervene with respect to the return on equity. The return on capital is a different type of cost parameter than operating costs. Operating costs, like many costs a utility faces, are unique to the specific utility and within its control. The cost of capital, however, is determined on a formula basis. Past practice is to have these rates similar for groups of utilities. In other words, the return on equity, and for that matter the cost of capital generally, is usually determined on a generic basis.

5.2.7 While there is a strong argument that the return on equity should be updated utilities that file on a forward year basis, the Board is concerned that this will create confusion on capital markets. It may be perceived that a utility is penalized because it chose to file on a forward year basis. Utilities of course compete with each other in capital markets, which adds another dimension to the problem. And, as a matter of law, utilities are entitled to earn a rate of return that not only enables them to attract capital on reasonable terms but is comparable

[6] Transcript, Volume 4, p. 3

30

to the return granted other utilities with a similar risk profile[7] The manner in which they file their application does not fall within the jurisprudence.

5.2.8 Toronto Hydro also argues that if the Board only looks at the economic variables in the ROE it amounts to "cherry-picking". The utility claims that it is improper to isolate economic variables without looking at other cost of capital issues such as debt to equity ratios. Toronto Hydro says that it is the most highly leveraged utility in the province with a debt toequity ratio of 65:35. That ratio was initially established in the Board's March 2000 Distribution Rate Handbook.

5.2.9 Toronto Hydro notes that a historic test year filer with a 50/50 debt to equity ratio would attract a 9% return on a higher equity base than Toronto Hydro. The higher equity base and rate, they say, creates an unfair advantage in capital markets. Toronto Hydro believes that a 60/40 ratio would be more appropriate in its case, but accepted the 65/35 debt to equity ratio "as part of the bundle of the OEB's rate-making policies contained in the new Handbook for this next generation of LDC rates."

5.2.10 The Board accepts this argument. The long Canada bonds are just a part of the picture. The cost of capital should be updated to reflect current market conditions, but it should be done on a comprehensive and generic basis. Dealing with it piece-meal just leads to confusion in the markets with potential unfairness to investors, the utility, and ultimately the customers.

5.2.11 Having considered the generic aspect of this particular cost item – the consequences for the financing costs of particular utilities and the consequences of that in turn to ratepayers – the Board has determined it will accept the 9% rate of return on equity for Toronto Hydro. The Board would emphasize that this ruling applies to the 2006 rate year only and should not be taken as a precedent beyond that.

5.2.12 In making this determination the Board is attempting to balance the interests of all parties. It is also relevant that the Board has announced its intention to review the cost of capital, including the equity risk premium, for electricity distributors before 2008.

[7] Northwestern Utilites v Edmonton [1929] SCR 186 at 193; British Columbia Electric Railway Co v British Columbia Utilities Commission [1966] SCR 837 at 854; Federal Power Commission v Hope Natural Gas Co, 320 US S41 (1944) at 603..

5.2.13 In short, cost of capital is one item that is better dealt with on a generic basis. This ruling should not be interpreted as departing from our ruling on the motion with respect to the application of the Rate Handbook to forward test year filers. This ruling relates to the unique aspect of cost of capital, and then only for the 2006 rate year. The manner in which the cost of capital will be updated for all utilities will be addressed by the Board in the near future.

5.3 DEBT RATE

5.3.1 The Toronto Hydro application uses the Handbook's methodology for calculating the weighted average debt rate.

5.3.2 A number of parties were concerned that THESL is paying interest on a loan to its parent, Toronto Hydro Corporation, at an interest rate in excess of current market rates. This loan is in the amount of $980 million at an interest rate of 6.8%. There was general consensus that the current market rate is 5% and the extra 1.8% interest amounts to approximately $16 million per year.

5.3.3 When asked why the utility had not refinanced the debt at a lower rate, the witnesses responded that the decision was solely up to the City of Toronto.

5.3.4 The fact that the Board and most of the parties in this proceeding were concerned about the above-market interest rates during the course of this hearing would have been apparent both the utility and its shareholder the City of Toronto. The response by the City was interesting, to say the least. Once the hearing was over, they chose to extend the note to 2013.

5.3.5 The utility's defence of this interest rate is that it is the deemed rate specified in the Handbook. Toronto Hydro acknowledges that it would be subject to a lower deemed debt rate for any new debt but argues that the 6.8% rate on the existing note should be left in place because it was compliant at the time the note was put in place. Appendix A of the promissory note defines the debt rate applicable to the note as "the rate of interest per annum that at all times is equal to the debt cost rate that is prescribed from time to time by the Ontario Energy Board in its Electricity Distribution Rate Handbook for utilities in the same rate base class."