RP-1999-0001

IN THE MATTER OF the *Ontario Energy Board Act*, 1998;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd., carrying on business as Enbridge Consumers Gas, for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas for its 2000 fiscal year.

BEFORE: Paul Vlahos
Presiding Member

Sheila K. Halladay
Member

DECISION WITH REASONS
Phase 1

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APPENDICES

1. INTRODUCTION

1.1 THE PROCEEDING

1.1.1 By application dated January 7, 1999, The Consumers' Gas Company Ltd., carrying on business as Enbridge Consumers Gas ("Enbridge Consumers" or the "Company"), applied to the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* (the " Act") for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for its 2000 fiscal year, commencing October 1, 1999 (the "test year"). The Board assigned file number RP-1999-0001 to the application.

1.1.2 By letter dated March 12, 1999, the Coalition of Eastern Natural Gas Aggregators and Sellers ("CENGAS") filed a Notice of Motion under section 29 of the Act ("CENGAS Motion"). The CENGAS Motion asked the Board to refrain from exercising its ratemaking powers with respect to the Company's billing, collection, customer accounting, and related functions, or services and to direct the Company to take such steps as may be necessary to enable gas marketers to provide such services to their customers in the test year.

1.1.3 The Board issued Procedural Order No.1 on April 1, 1999 and thereby established the procedural framework for this proceeding. An Issues Conference was held on April 12, 1999 where the participants reached complete agreement on a list of issues to be presented to the Board for the purposes of the proceeding. On April 13, 1999, CENGAS and Enbridge Consumers informed the Board of their agreement to adjourn the CENGAS Motion. On April 16, 1999 the Board issued Procedural Order No. 2 approving the Issues List.

1.1.4 By Notice of Motion dated April 22, 1999, the Consumers' Association of Canada ("CAC"), the Industrial Gas Users Association ("IGUA"), and the Ontario Coalition Against Poverty ("OCAP") sought an order of the Board varying the EBRO 497-01 Decision and the Issues List in this proceeding. The motion was heard on June 8, 1999 and the Board issued its decision on June 14, 1999 dismissing the motion.

1.1.5 By letter dated May 7, 1999, the Company advised the Board that it would be filing updated evidence to address the EBO 179-14/15 and EBRO 497-01 Decisions. On May 19, 1999, the Board issued Procedural Order No. 3 setting dates for the filing of updated evidence, supplementary interrogatories and responses, evidence from intervenors and Board Staff, and related interrogatories and responses.

1.1.6 By letter dated June 3, 1999, CENGAS asked the Board to resume the CENGAS Motion and, moreover, to hear the motion prior to the oral hearing in this proceeding. On June 29, 1999, the Board heard submissions on the so-called threshold issues; that is, whether the Board was required to hear the motion and, if so, whether the motion should be heard in this proceeding. The Board ruled that it was not prepared to hear the motion prior to the oral hearing.

1.1.7 On June 30, 1999, the Board issued Procedural Order No. 4 setting the dates for a Settlement Conference and the commencement of the oral hearing. The Settlement Conference was held over five days in the period from August 3, 1999 through August 9, 1999.

1.1.8 During the Settlement Conference, discussions among the participants with respect to the issues enumerated under "Unbundling of Services" (issue 7) in the Issues List led to a consensus that a more detailed scoping of the unbundling issues was needed for hearing purposes. There was also consensus on the means of defining the scope of these issues, namely a series of questions pertaining to each issue and an indication of the status of each question in terms of readiness for hearing. The Company filed this document with the Board, on behalf of the participants, by letter dated August 10, 1999. By letter dated August 12, 1999, Union Gas Limited ("Union") expressed concern about the impact that a hearing of the unbundling issues in this proceeding might have on discussions at its proposed settlement conference in the RP-1999-0017 proceeding and, as a result, requested that the consideration of unbundling issues in this proceeding take place after Union's proposed settlement conference. The Board sought comments from the Company and the other parties in this proceeding with respect to the request of Union.

1.1.9 In the meantime, the Board issued Procedural Order No. 5 on August 11, 1999. This order set the date for a Technical Conference with respect to the evidence of IGUA, CAC, and the Vulnerable Energy Consumers Coalition ("VECC"), which replaced the intervention by OCAP. The Board subsequently issued Procedural Order No. 6 on August 13, 1999, cancelling the Technical Conference and replacing it with an interrogatory process. By the same order, the Board set August 23, 1999 as the date for the commencement of the oral hearing.

1.1.10 After the conclusion of the Settlement Conference, the Company prepared a Settlement Proposal in consultation with the other participants in the Settlement Conference. The Company filed the Settlement Proposal with the Board at the commencement of the oral hearing on August 23, 1999. The Settlement Proposal was subsequently revised in order to incorporate the settlement of additional issues.

1.1.11 The Board accepted the Settlement Proposal on August 26, 1999 subject to the usual caveats regarding significant events and possible connectivity of unsettled issues that may affect the settled issues. The Settlement Proposal, as finalized, appears in Appendix C in this Decision.

1.1.12 The Board sought clarification regarding the implementation of the gas cost increase in rates, as contemplated by the settlement of that issue, on an interim basis effective October 1, 1999. The Board then directed the Company to prepare a draft rate order reflecting the changes in gas costs as agreed to by the parties and to forward it to the Board with the usual supporting documentation. The Company complied with this directive on September 17, 1999. The Board's Interim Rate Order RP-1999-0001 was issued on October 1, 1999 for new rates effective as of the same date.

1.1.13 After the Settlement Proposal was filed with the Board, the Company prepared a Scoping Proposal in consultation with the other parties who participated in the Settlement Conference. The Company distributed the Scoping Proposal in its initial form on August 26, 1999. The ensuing discussion established the purpose and status of the Scoping Proposal, namely to define, for reference purposes, the scope of the unsettled issues and of the conditional aspects of two settled issues. The Company filed the final version of the Scoping Proposal on August 27, 1999.

1.2 THE HEARING

1.2.1 The oral hearing commenced on August 23, 1999 and concluded on September 9, 1999 after 12 hearing days. At the commencement of the oral hearing, the Board announced its decision to defer the unbundling issues to a separate phase of this proceeding and that the Board would issue a procedural order, in due course, that would establish a procedural schedule for the separate phase, including provision for new evidence and a settlement conference. The argument phase of the oral hearing was completed on October 21, 1999.

1.2.2 The issues addressed in this Decision are those for which there was no settlement. The parties to the proceeding and the names of the witnesses who testified at the hearing appear in Appendix B. In this Decision the Board uses the abbreviated names for the parties listed in Appendix B.

1.2.3 Copies of all the evidence, exhibits and arguments filed in the proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices. While the Board has considered all of the evidence and submissions presented in this hearing, the Board has chosen to cite these only to the extent necessary to clarify specific issues on which it has made findings.

2. CLASSIFICATION ISSUES

2.0.1 This chapter deals with the classification of two of the Company's activities, the Natural Gas Vehicles (NGV) Program and the Home Gas Appliance Inspection (HGAI) Program.

2.1 NATURAL GAS VEHICLES (NGV) PROGRAM

2.1.1 The NGV program has been redefined for the purposes of cost allocation and rate design in accordance with the terms contained in EBRO 497 (rates case for the Company's fiscal year 1999). The redefinition distinguishes that part of the program that requires rates to be approved by the Board (the regulated component from the rest of the NGV program (the unregulated component). The regulated component of the NGV program includes the sale of natural gas under Rate 9, the provision of the infrastructure that is required to deliver natural gas in a useable form, and the marketing of natural gas for use as vehicle fuel. The unregulated component includes the NGV cylinder rental program, NGV fuel systems (i.e. the design, warehousing, and distribution of NGV conversion kits), and NGV sales (i.e. the sale of conversion kits and rental cylinders).

2.1.2 In EBRO 495, the Board found that the unregulated component of the NGV program should be treated as an ancillary program subject to fully allocated costing. The Board's decision was reaffirmed in EBRO 497. In the current proceeding the Company is seeking to continue the NGV program as an ancillary program but without imputing revenue, in this case $0.7 million, to bring the forecast profitability of the program to the overall rate of return for the utility.

2.1.3 The focus of intervenors' arguments (CAC, Energy Probe, IGUA, Schools, and VECC) was that there has been no change in circumstance and therefore full costing should apply to the NGV program. In order to achieve this, certain intervenors suggested that the NGV program be treated as non-utility, in which case full costing would apply, while others did not oppose the classification of the program as ancillary as long as the appropriate revenue imputation was made so that there would not be any cross-subsidization between the regulated utility business and the NGV program.

2.1.4 The Company indicated that, given its relatively small size, the NGV program operates and functions as one undivided business unit, sharing resources between the regulated and unregulated components. Also, since some 90% of the total revenue and over two-thirds of the capital investment of the program are included in the regulated component of the program, the issue pertains to a very small portion of the program. Further, the Company noted that the life expectancy of the unregulated component of the program is expected to diminish over time and be completely taken over by the marketplace within five years. Finally, the Company indicated that a Board direction to move the unregulated component outside of the Company by transferring it to an affiliate would create significant practical problems as a result of the constraints stipulated in the Board's *Affiliate Relationships Code for Gas Utilities* (the “Code”).

2.1.5 For all of the reasons cited above by the Company, the Board finds that the sharing of resources between the rate regulated and unregulated components is a reasonable approach and a non-utility classification of the unregulated component would introduce unnecessary complexities and inefficiencies. The Board therefore reaffirms its earlier decisions that the NGV program be continued to be classified as ancillary. The distinction between the rate regulated and the unregulated components, however, remains meaningful for cost allocation purposes. The Board has noted the Company's arguments in support of its request for no revenue imputation, including the reference to letters of support sent by certain organizations, that the NGV program is an important program from the perspective of the community within which it operates, from the perspective of society because of the environmental benefits of using natural gas as a vehicle fuel, and from the overall natural gas sales volume perspective. Similar arguments have been placed before the Board by the Company on numerous occasions and the Board was not persuaded on those occasions that these reasons were sufficient to permit cross subsidization.

2.1.6 The Company cited two special circumstances in this case in support of its request for the Board not to impute revenue. The first is the stated intention of the Company's shareholder to reconsider the future of the unregulated component of the program in the event the Board decides to impute revenue. The Board does not see how this constitutes a special circumstance. The Company's shareholder could have always availed itself of that opportunity since the program is not a distribution utility activity. In fact, the Company itself recognizes that there are efficiencies and reduced complexities in having the program operating as a unit. In its findings above the Board has recognized this by allowing the program in its totality to be treated as ancillary.

2.1.7 The second special circumstance cited is that the unregulated component comprises a very small portion of the overall program and that these activities will be taken over by the marketplace within five years in the form of dedicated natural gas powered vehicles. Again the relative size argues for treating the totality of the program as ancillary as the Board has done. The requested cross-subsidy of $0.7 million however is not immaterial. Presumably, as the unregulated component is taken over by the marketplace as the Company anticipates, the level of imputation necessary will likely decline correspondingly, thereby resulting in lesser concern for the Company's shareholder.

2.1.8 For all of the above reasons, the Board imputes revenue of $0.7 million in the test year on account of the NGV program.

2.1.9 The Board notes that the retention and revenue imputation issue with respect to the NGV program has been before the Board on a number of occasions of late. In future, the Board expects the Company to be guided by the Board's numerous decisions in this regard and not to unnecessarily cause revisitation of the same issues unless there are significant new circumstances not previously addressed by the Board.

2.2 HOME GAS APPLIANCE INSPECTION (HGAI) PROGRAM

2.2.1 In accordance with EBRO 497 which provided that the Company would file cost information, including rate of return schedules prepared on a fully allocated basis, for any appliance service program that the Company proposed to provide during the 2000 test year, the Company filed evidence that describes the HGAI program and the Company's reasons why the program should continue as part of the core utility. The Company also filed evidence that describes the cost allocation process used to determine the allocated costs that were, in turn, used to derive the rate of return of the program.

2.2.2 The test year revenue for the program is forecast at $319,000 on an estimated 4,000 calls. The Company's evidence was that the program is estimated to under-recover in the amount of $231,000 in the test year on a basis of full costing. The service is not promoted but is provided in response to customer concerns following the triggering of CO detectors. The service is an inspection of the customer's home and appliances to ensure that there are no sources that pose a safety threat.

2.2.3 The Company proposed to include the HGAI program as part of its core utility operations and, as such, not separately identify and fully cost the activities of the program. Intervenors (HVAC, CAC, IGUA, Schools, and OAPPA) argued that the program should be treated as an ancillary program, costed on a fully allocated basis.

2.2.4 The Company noted that there are three important points to keep in mind in considering the classification to be applied to the HGAI program. The first is that there is an obvious nexus between the Company's gas distribution business and the service provided under the HGAI program. The second is that the service provided under the HGAI program, albeit not an emergency service, is nevertheless a safety service provided in response to safety concerns expressed by customers. The third is that, at this time, there is no one else in the marketplace who offers the type of service provided by the HGAI program.

2.2.5 The Board notes that no party argued for the removal of the HGAI program from utility operations. Rather, the proposals were for treating the program as ancillary, which, according to some, would automatically attract full costing for ratemaking purposes. Also, in IGUA's view, the existence of specific unregulated charges for the service should automatically characterize the program as ancillary.

2.2.6 In the Board's view the issue is complicated by the Company's position. The Company argued that the program is a safety related activity but did not claim that this should be determinative in classifying the program as core utility. Instead, the Company suggested to continue to offer the program as part of its core utility activities until such time as there are other service providers who are able and willing to offer the same kind of service. The problem with that suggestion is that, as long as the utility program does not recover its full costs, it is questionable whether a third party would be willing to provide such an offering if it is unable to compete on price.

2.2.7 The Company's position leads to the conclusion that it views the program as contestable. On that basis, the program in the Board's view should be classified as ancillary. However, the safety aspects of the program and the absence of alternative offerings at this time constitute special circumstances. Therefore, the Board finds that the HGAI program will be classified as ancillary but without revenue imputation for the test year. Should it be demonstrated in a future rates case that there are other service providers willing and able to offer the same type of service, the Board's findings will be reassessed. Such evidence must come directly from potential service providers, not only from associations representing such entities.

3. CONSEQUENCES OF RENTAL PROGRAM REMOVAL

3.0.1 Following the Board's EBO 179-14/15 Decision, in which the Board rejected the Company's request to include its rental program as part of the core utility, the Company decided to transfer its rental program to an affiliate. This chapter deals with matters flowing from the Company's decision. Specifically, the issues dealt with are:

- Deferred Income Taxes;
- Capitalization of A&G Overhead Expenses;
- Separation Costs; and
- Cost of Capital.

3.1 DEFERRED INCOME TAXES

3.1.1 In its EBO 179-14/15 Decision, the Board made the following ruling on the question of deferred income taxes associated with the rental program:

> It therefore appears to the Board that utility ratepayers have benefitted from the rental program over the years, and that the shareholder has absorbed some costs. While finding that ratepayers should not be responsible for the deferred tax liability, *per se*, related to the rental

> program, the Board believes that there should be some recognition of the benefits they have received in the past. The Board therefore would accept the provision of a notional utility account in the amount of $50 million, after tax, to allow the shareholder to use the value of these past ratepayer benefits to pay a portion of the deferred taxes associated with the rental program as they become due. It is up to the Company to determine the future of the program, but whatever that choice, the notional account can be drawn down to pay deferred taxes up to $50 million.

3.1.2 The Company confirmed at the hearing that it would be transferring its rental program assets to an affiliate (Enbridge Services Inc.) on October 1, 1999 by way of a rollover under section 85 of the *Income Tax Act*, that is, it would be transferring the tax liability to the affiliate. The Company proposed to recover in the test year $11.9 million after tax ($21.2 million on a pre-tax basis) in deferred income taxes associated with the rental program.

3.1.3 Intervenors argued that no deferred tax amount should be recovered in rates until there is proof that taxes associated with the rental program have been paid by the affiliate. The suggestion for appropriate proof centered around the production of a certificate by the auditors of Enbridge Services Inc. It was also suggested that such certificate should be on the basis of the corporate entity (Enbridge Services Inc.) as a whole, not on a stand alone basis for the rental program only.

3.1.4 The Company contended that the meaning of the words in the EBO 179-14/15 Decision is that the notional utility account can be drawn down as the deferred taxes become payable, not that they have been paid. It was the Company's position that there is nothing to suggest that the notional account should be treated differently from other rate-making matters that are viewed on a forecast basis for any test year. The Company also argued that it is inappropriate and impractical to suggest that, on a year by year basis, the Company must support its forecasts of deferred taxes with certificates from auditors.

3.1.5 The Board notes that the deferred tax amount that is being requested for recovery in rates represents the difference between the deferred taxes payable under a rental program winddown mode in the utility (rejected by the Board in EBO 179-14/15) and a business as usual scenario (ancillary classification), both within the utility. The Company's support for this amount is the confirmation by the Company's witness that the rental program would be transferred to Enbridge Services Inc. As for the wind down of the rental program by Enbridge Services Inc., the Company's witness stated that "in its existing structure it [the rental program] will be wound down". Upon probing, the witness stated that "Hot water units will still be available from Consumersfirst [Enbridge Services Inc.] and can be purchased and financed or leased, but they will not be rented as part of the current program". Upon further probing, the witness stated "... [hot water units] will be financed or leased, but not rented". The witness later stated that "that is our current plan".

3.1.6 Payment of the deferred taxes associated with the rental program arises according to the Company from a wind down mode. However, the testimony by the Company's witness is neither definitive that the rental program will be "wound down" nor clear as to how it will be "wound down" thereby triggering incremental taxes payable within the affiliate. The Board is not prepared to consider the other arguments by the parties unless there is a better understanding on these issues, which must come from a more complete and clear record. The Board therefore denies the Company's request to recover the requested amount for deferred taxes in the test year.

3.2 CAPITALIZATION OF A&G OVERHEAD EXPENSES

3.2.1 The Company proposed to capitalize $20.1 million of Administrative and General Overhead expenses ("A&G O/H") in the test year. This amount is arrived at by starting with the 1999 approved amount of $20.8 million, adding $0.2 million for unbundling, and deducting $1.9 million for the wind down of the rental program. The O&M PBR factor is applied to the net amount of $19.1 million to arrive at the Company's $20.1 million proposal for A&G O/H expenses.

3.2.2 Six intervenors (IGUA, CAC, HVAC, Schools, Energy Probe, and VECC) argued that since the rental program accounted for $9.1 million of A&G O/H expenses in 1999, the removal of the program results in a shift of $7.2 million ($9.1 million minus $1.9 million) from rental customers to ratepayers for the test year which shift ought not to be permitted.

3.2.3 The Board finds the Company's evidence and argument on this issue confusing, and at times contradictory. The Company noted that the fiscal 1999 $9.1 million allocation to the rental program reflected in rate base was determined in accordance with the pro rata allocation methodology which assumes that each asset group attracts A&G O/H costs at the same rate. The Company argued that since there will be no expenditures on rental equipment by the utility, there should be no allocation of A&G O/H expenses to that program in fiscal 2000. Having eliminated $1.9 million attributable to the rental program wind down results in the Company distributing the remaining $7.2 million to utility asset construction. The allocation is made on a pro rata basis which leads to the Company's position that the allocation methodology has not changed from what the Board had approved in EBRO 497 for fiscal 1999 which serves as a base for the unbundling. Elsewhere in the evidence and argument the

Company noted that it had reviewed the allocation methodology on the basis of the Board's EBRO 497 Decision and the result of that review has been reflected in its evidence in both EBO 179-14/15 and EBRO 497-01 which gave rise to the $1.9 million elimination for winding down the rental program. At the same time the Company argued that the $11.7 million portion of the A&G O/H expense associated with other non-rental activities, approved by the Board in EBRO 497, bears no relationship to the costs that will be required to support additions to capital in the unbundled utility which brings the issue back to the Board's rejection of the Company's proposal in EBRO 497 to alter the pro rata methodology.

3.2.4 Clearly the Company's current proposal produces precisely the same effect as there would be had the Company's proposal in EBRO 497 been accepted rather than rejected. The issue then for the Board is whether the $7.2 million left in the utility's rate base results in just and reasonable rates.

3.2.5 In assessing reasonableness, the Board is not persuaded by intervenors' arguments that the test that ought to apply in this instance is "no harm to ratepayers" by eliminating not only the direct and marginal costs but also the previously allocable costs. The "no harm to ratepayers" test applied by the Board in the EBO 177-17 case, dealing with Union's separation of non-utility programs, was specific to the requirement of the then applicable Union Undertakings. In EBO 179-14/15 the Board used the "no harm to ratepayers" test in assessing the removal of assets and expenses associated with the non-utility programs that were being transferred out of the utility. The Board accepts that removing non-utility activities from the utility will in many cases leave some costs behind which cannot be eliminated in a short time frame. The issue then is what would be an appropriate time frame to eliminate these costs. As in the case of O&M costs discussed elsewhere in this Decision, the Board finds that it would be reasonable to expect that further rationalization will eliminate half the $7.2

million cost, or $3.6 million, within three years. The Board deems that these savings will be achieved equally over the years 2000, 2001 and 2002. The deemed savings therefore for each of these years is $1.2 million.

3.2.6 The Board therefore reduces the Company's gross plant in service for the 2000 test year by $1.2 million. For the purposes of determining the rate base impact of this adjustment, the Board has attributed this A&G adjustment to construction projects entering service uniformly during the test year thereby resulting in a $0.6 million reduction to rate base. The Board recognizes that there may be some adjustments to other components of rate base and utility income associated with the above reduction but in light of the insufficient evidence on the record the Board deems the net impact of such adjustments to be not substantial for purposes of determining the total revenue requirement for the test year. The Board directs that the Company's cost of service filings for each of the fiscal years 2001 and 2002 reflect the appropriate adjustments with supporting details for other components of rate base and utility income.

3.3 SEPARATION COSTS

3.3.1 The Company proposed to recover one-time costs associated with the separation of the rental program in the amount of $11.4 million. The Company stated that the benefits from this expenditure have already been reflected in the proposed rates for fiscal 2000. The Company proposed to amortize this amount through a deferral account mechanism (Unbundling Business Activities (UBA) Deferral Account) and recover it from ratepayers over a three-year period. Accordingly, the 2000 test year cost of service includes an amount of $3.8 million for this item.

3.3.2 A summary of the transition costs are shown in the following table:

Item	**Amount**
	($ millions)
Costs Related to the Realization of Future Savings	6.9
Transition Planning	1.2
Communications	1.3
Code Compliance and Regulatory	2.0
TOTAL	11.4

3.3.3 Allowance of these costs according to HVAC, IGUA, and Energy Probe, would result in a transfer of the rental program at below book value, which is contrary to the principles espoused by the Board in the EBO 177-17 Decision. It would also be contrary, according to Schools, CAC, and IGUA, to the Board's EBO 179-14/15 Decision. CAC also argued that these are out of period costs and therefore not recoverable, while IGUA viewed the majority of these costs equivalent to a request for an "in year" deferral account relief which ought to be assessed against the Company's overearning situation for the 1999 fiscal year. HVAC noted that the customers for which the Company is easing the transition are not utility customers and that transition planning costs are driven by restructuring, not by the utility business.

3.3.4 In EBO 179-14/15, the Company's application included a request for recovery of $19.3 million in claimed costs related to the proposed restructuring, which included the transfer of certain non-utility programs, the request that the rental program be classified as core utility in a wind down mode, and the elimination of 173 positions due to utility restructuring. The Company had not identified the costs relating to each element of its application. In the Board's Decision on that application, the Board noted that the portion of the transition costs relating to the transferred programs would reduce the net transfer value of the transferred assets to below book value and therefore ratepayers would not be held harmless by the transfer. In the present proceeding the Company identified such costs to be $7.9 million. The Company stated that no recovery of these costs is being sought.

3.3.5 For the present proceeding, the Company claimed $11.4 million in separation costs as set out above. Of the $11.4 million in total claimed costs, $4.5 million (Transmission Planning, Communications, Code Compliance and Regulatory Costs) is related to activities that the Company has undertaken or plans to undertake to "ensure a smooth transition to a core distribution utility for customers, employees, and the public, and to maintain compliance with the Affiliate Code". In support of its request for recovery of these costs, as well as other costs that arise from the transfer of the rental program, the Company took the position that these costs were brought about by the Board's EBO 179-14/15 Decision or were incurred to comply with that Decision. The Company also stated that the Board included the rental program in regulation for years.

3.3.6 The Board reiterates that just because an ancillary program is part of the legal entity regulated by the Board does not mean that the program is "regulated". The Board repeats that it has never set the rental program rates. The Board's role has been to ensure that there were no undue subsidies arising from the operation of the non-utility ancillary programs by imputing revenue where deemed necessary. The Board did not direct in its EBO 179-14/15 Decision that the rental program be transferred out of Enbridge Consumers. At that time the Board had no authority to do so. The Board rejected the Company's proposal concerning the treatment of the rental program for the reasons stated in that Decision. The Board commented that should the rental program remain within Enbridge Consumers, for ratemaking purposes the rental program would have to be classified as a non-utility activity. This would have the same effect as an ancillary program under fully allocated costing as has been the case since EBRO 495.

3.3.7 Based on the evidence and arguments, the Board finds that not all of the $4.5 million of claimed costs are appropriately recoverable in rates. The benefit from these expenditures largely accrues to the Company's rental customers and the Company's shareholder. Recovery of the full claimed amount would in effect lower the transfer value of the rental program to Enbridge Services Inc. to below book value. The Board on the other hand accepts that implementing the transition and communicating it to various stakeholders is ultimately of some benefit to the ratepayers. Based on the evidence available in this proceeding a precise quantification is not possible. The Board therefore finds that it is reasonable to deem about half of the $4.5 million costs or $2.3 million as recoverable from ratepayers.

3.3.8 The $6.9 million costs for the realization of future savings relate to the planned reduction of 173 positions. The Company argued that these are recoverable costs since the benefits have already been reflected in the unbundled O&M budget. The Board agrees that there are direct savings to ratepayers associated with the reduction of the positions and these labour related costs are therefore recoverable from ratepayers. However, the Board finds that not all of the savings have been reflected in the unbundled O&M budget as the Company claimed. According to the evidence only $1.6 million of the total savings is reflected in the O&M base budget used to set rates for 2000. A further $2 million would be reflected in 2001 and a further $1.6 million in 2002.

3.3.9 The Board therefore finds that a total of $9.2 million ($2.3 million plus $6.9 million) in separation costs is recoverable from ratepayers. The Board accepts the Company's proposal to amortize such expenses over a three year period, or $3.1 million per year. Since the Company has included an amount of $3.8 million in rates for fiscal 2000, the Board therefore reduces the test year's proposed separation expenses by $0.7 million. The balance of $6.1 million shall be recorded in a deferral account as proposed by the Company to be amortized over years 2001 and 2002. However, the balance in such deferral account for disposition shall also include customer credits of $1.6 million for 2001and $2.0 million for 2002.

3.4 COST OF CAPITAL

3.4.1 With the transfer of the rental program, the Company's evidence indicated that the resultant utility capital structure would contain a negative short-term debt component, since the embedded long term debt according to the Company must remain with the utility in accordance with the terms of the debt. The Company proposed to treat the negative short-term debt as an investment earning a return equal to the forecast 90-day commercial paper. The impact on the revenue requirement in the test year was calculated as $11.1 million. The Company noted that this is a temporary aberration to the capital structure.

3.4.2 In the Company's view, the key issue is whether or not the Company has prudently managed its financing plans based on the forecast operating environment and circumstances for the test year. Certain intervenors argued that the increase to the cost of capital should be disallowed on the grounds that the "no harm to ratepayers" principle found by the Board in EBO 179-14/15 is being violated.

3.4.3 The Company argued that this aberration would occur even if the rental program was not transferred but was retained within Enbridge Consumers as a non-utility activity and therefore the $11.1 million impact would be recoverable from ratepayers. The Board is not convinced that this is necessarily the case. In any event, this position by the Company is inconsistent with the just and reasonable rates test that the Company asked the Board to adopt in deciding other matters resulting from the transfer of the rental program.

3.4.4 Based on the accepted practice of using a deemed capital structure in setting rates for the Company, short-term debt serves as a balancing item to equate total rate base with capital structure. In normal circumstances the balancing item is a positive amount; otherwise ratepayers would be burdened by poor planning by the utility. While the Company had the right to arrange its non-regulated businesses as it saw fit, its choice and the timing of that choice have resulted in costs being left behind in the utility. The Board accepts that an optimal capital structure may not be possible for the 2000 test year. However, a sub-optimal capital structure ought not to result in a negative debt (cash position) at an investment return that, in this case, is below the embedded cost of long term debt. The Board therefore deems a capital structure where the short-term debt component is zero and the long term debt component is the balancing item to equate total capitalization with rate base with no change to the proposed embedded cost of long term debt. The details of the Board-approved notional capital structure for the 2000 test year are shown in Appendix A. The Board expects the Company's capital structure in the next rates case to reflect more traditional capital ratios.

4. CUSTOMER INFORMATION SYSTEM (CIS)

4.1 BACKGROUND

4.1.1 The Customer Information System (CIS) is the final project of the Strategic Information Management (SIM) plan. It is not the Board's intention to dwell on the history of the CIS project, however, it is important to briefly highlight some of the Board's concerns expressed throughout the project's development, particularly with regard to the management of the project and the escalation of costs.

4.1.2 The SIM plan was first presented to the Board in EBRO 473 (fiscal 1992). In EBRO 487 (fiscal 1995), the Board ordered a Board-supervised audit of the entire SIM plan, of which CIS is the largest part, to verify that the costs incurred were reasonable, the benefits proposed were achievable and that the Company's plans were reasonable and within its capacity.

4.1.3 In EBRO 492 (fiscal 1997), the Board indicated three areas of concern regarding the project: the adequacy of CIS to service new future business activities of Enbridge Consumers, the prudence of the costs associated with the Coopers & Lybrand engagement and the integrity of the forecast and cost controls supporting the CIS project. The Board found that the Company had not demonstrated an adequate ability to forecast and control CIS costs and the evidence submitted did not indicate that conventional and understandable project planning and budget control techniques, such as critical path analysis, were used.

4.1.4 In EBRO 495 (fiscal 1998), the Board again expressed concerns about the CIS project and noted that the onus was on the Company to provide the Board at the next rates case with sufficient information about the engagement of PriceWaterhouse ("PW") to enable the Board to decide whether or not the Company was prudent in entering into this arrangement. The Board also concluded that it did not yet have the requisite evidence to make a finding as to the prudence of the Company's expenditures on CIS up to that point. The details of the failed relationship with PW as the prime CIS contractor, including the full nature and costs were never disclosed.

4.1.5 In EBRO 497 (fiscal 1999), the Company indicated that the CIS project was under review and did not present evidence in that case.

4.1.6 When it became apparent that the original project plan under the leadership of PW, could not be completed on an acceptable schedule or budget, the project was shut down for a year and restarted in January 1999.

4.1.7 Since EBRO 473, the forecasted costs for CIS have escalated from $22.2 million to $119.9 million.

4.2 PROPOSAL

4.2.1 When the Company filed its original evidence in this proceeding in February 1999, the Company proposed to close the entire $119.9 million costs associated with the CIS project to rate base. In May 1999, the Company advised the Board and the intervenors of its revised plans, under which it proposed to divide the costs of the CIS project into costs relating to the CIS software and all other costs. The Company's proposal is set out below.

4.2.2 The Company would transfer the CIS software effective October 1, 2000 to an affiliated company to be incorporated ("Newco") at net book value at the time of transfer, which the Company estimated to be approximately $89.6 million.

4.2.3 The Company would include all other non-software costs of the CIS project, of approximately $30.3 million to rate base, effective October 1, 1999 as follows:

- $10.5 million - direct costs for Business Process Re-engineering ("BPR") work and analysis phase work;
- $13.4 million - indirect cost allocation of SIM start-up and overhead costs; and
- $6.4 million - interest during construction on direct and indirect costs.

4.2.4 The Company would include Newco's annual fees of $15.8 million as a CIS Z factor under the Targeted O&M PBR plan. This amount would be reduced in the test year by the following offsetting items:

- $3.6 million in hosting revenue for the use by Newco of the Company's infrastructure to run the CIS software;
- $4.1 million as a phase-in-credit, reflecting the staged releases of the CIS functions;
- $0.5 million in reduced information services O&M costs; and
- $1.9 million of reduced customer service O&M costs.

4.2.5 The net amount to be included in the CIS Z factor for the test year would therefore be $5.7 million.

4.2.6 The specific components of the proposal and the Board's findings are set out below.

4.3 TRANSFER OF CIS SOFTWARE TO NEWCO

4.3.1 As noted above, the Company did not make the decision to transfer the CIS software to an affiliate until May 1999 after it had filed its initial evidence in this proceeding. The Company's rationale for this proposed change of strategy with respect to CIS was the Board's decision that the rental program should be treated as a non-utility business and the associated implications of unbundling. A number of intervenors questioned the sincerity of the reasons given by the Company for its decision and noted that the proposal to transfer the CIS software to an affiliate had all of the earmarks of an artificial arrangement. A number of intervenors also questioned whether the arrangement was a true outsourcing proposal or was merely a financial arrangement as was suggested by Mr. Stephens, a witness testifying on behalf of certain intervenors. Many intervenors noted that by reconfiguring the proposal the Company has avoided detailed scrutiny of the CIS project.

4.3.2 The Board notes that the Company does not require Board approval to transfer the CIS software to an affiliate. It is in the Company's sole discretion to transfer the CIS software to Newco and to determine the specific assets being transferred. However, the cost consequences that arise as a result of the Company's decision to transfer the CIS software are indeed relevant for ratemaking purposes.

4.4 "PRE-PROJECT" COSTS

4.4.1 The Company advised the Board that all costs associated with the SIM projects were accumulated in a work in progress account (SIM WIP Account). As SIM projects were completed and closed to rate base, amounts approved by the Board were deducted from the SIM WIP Account. CIS is the only SIM project that has not yet been closed to rate base and therefore it is the Company's position that all costs remaining in the SIM WIP Account relate to the CIS project.

4.4.2 According to the evidence, the Company attempted to model the provision of CIS services to the Company by Newco along the same lines as the CIS services provided to Union by its affiliate Enlogix Inc. ("Enlogix"). The Company attempted to match the services provided and the categories of costs incurred by the two CIS providers. The Company proposed that where in the Company's view there was a match in a specific service, the costs associated with the provision of that service would be transferred to Newco. Where there was no match in the service provided by Enlogix to Union, the costs would be closed to rate base. The Company proposed that these "pre-project" costs amounting to $30.3 million, deemed by the Company not to be CIS software-related, should not be transferred to Newco and therefore should be included in rate base.

4.4.3 In assessing the rate-making implications of the CIS costs proposed to be included in the rate base, the Board has adopted the following test. If the "pre-project" costs were incurred to directly develop the Company's CIS software, then all such costs should not be recoverable from ratepayers. If on the other hand the Company can establish that the costs were reasonably and prudently incurred for the benefit of utility ratepayers independently from the development of the CIS software, then the Board may make a determination to include such costs in the cost of service. However, since the major capital asset, namely the CIS software, is being transferred to Newco and not included in the utility rate base, the costs found to be independent from the CIS software cannot be reasonably viewed as capital costs or costs relating to a capital asset and therefore cannot be capitalized in rate base.

4.4.4 The Company originally proposed that $10.5 million of direct costs for Business Process Re-engineering work and analysis phase work should be included in rate base. This amount was subsequently subdivided into $5.4 million for BPR work and $5.1 million for the analysis phase work.

Business Process Re-engineering (BPR)

4.4.5 The Company contended that the BPR work focused on core customer related processes. The work was carried out in fiscal 1993 and 1994 in order to understand how the Company could change its processes to better serve customers. Instead of simply specifying a new CIS system to fit the then current business processes, the Company chose to seek opportunities to improve the workings of the business. According to the Company, a large number of good ideas came out of the BPR effort, some of which could be built into the scope and specifications for the new CIS software, and others could be implemented without waiting for the software.

4.4.6 The Company's evidence was that the BPR work yielded two main benefits:

- The utility achieved basic improvements in systems and processes that could be realized without software development. These improvements have been implemented and the benefits of which have been delivered to ratepayers.
- The effort generated information that was valuable in setting out the specifications for the new CIS.

4.4.7 In the Board's view, the BPR costs should only be recoverable from ratepayers if it is determined that the BPR costs are truly independent of the CIS software and yield independent benefits to utility ratepayers. The Board accepts that the link which was noted by parties was a result of accounting convention in reporting on the issue of SIM projects. The Board also notes that intervenors were not in general opposed to all or some of the BPR related costs being viewed as recoverable from ratepayers. The Board is satisfied that there have been benefits that resulted from the BPR effort, and to the extent these are utility related have been reflected in the Company's rates over the years and will continue to do so regardless of the implementation of the CIS software.

4.4.8 However, there is no persuasive evidence that the BPR expenditures were for the sole benefit of the gas ratepayers. Benefits also accrued to the Company's ancillary and non-utility activities. In this regard, the available information points to a proportion of 17% that may be reasonably attributable to these activities. The Board therefore deems that only 83% of the total $5.4 million BPR expenditures or $4.5 million is recoverable from ratepayers.

4.4.9 For the reasons stated earlier, the Board does not accept that this amount should be part of rate base. The Board deals with the ratemaking treatment of this amount, in conjunction with other amounts, later in this chapter.

Analysis Phase Costs

4.4.10 The Company also proposed that $5.1 million should be included in rate base for costs incurred by the Company in the analysis phase of the CIS project. These costs, by their nature, are not independent; they are associated with the implementation of the CIS software.

4.4.11 To assess the validity of recovering these costs from ratepayers, the Board must determine whether, in addition to the BPR costs of about $5 million, an expenditure of a similar amount for the Company to "figure out what it needs" can be viewed as reasonable.

4.4.12 The difficulty that the Board has in assessing the reasonableness of the Company's proposal to recover these costs is that the Company is essentially asking the Board to rewrite history. The Company has made the decision to transfer the CIS software to Newco and is now asking the Board to assume, retrospectively, that these costs would have been incurred if this had been the case all along.

4.4.13 Considerable time was spent on speculating whether the software manufacturer or the customer would have incurred the costs in developing detailed specifications for the computer system. Clearly if Newco were developing the CIS software system from scratch it would have had to analyze the requirements of its potential customers, as argued by intervenors in support of their position that the analysis phase costs should be transferred with the CIS software. In the Board's view, developing the detailed specifications required to develop a computer software program, as the Company was initially intending to do at the time many of these costs were incurred, is far more onerous and costly than merely determining what the Company's requirements were before seeking a solution in the marketplace.

4.4.14 While the Board finds merit in the intervenors' argument, the Board accepts that a prudent utility would have to incur some expense in analyzing its CIS requirements. However, the Board's finds that the claimed amount of $5.1 million is clearly excessive. On the other hand the Board views Mr. Stephens' analysis in this regard, which would yield an allowance in tens of thousands of dollars only, as too conservative. On balance, the Board deems that $1.5 million is a reasonable cost for the analysis phase of the utility's CIS requirements to be recoverable from ratepayers.

4.4.15 At the time these costs were incurred, the CIS system was being designed to serve not only the utility business, but also ancillary and non-utility activities, such as the rental program. As indicated above, the Board finds that 17% of the costs associated with the analysis phase are reasonably attributable to these ancillary and non-utility activities. The Board therefore deems that only 83% of the total $1.5 million in analysis phase expenditures or $1.25 million is recoverable from ratepayers.

4.4.16 The Board deals with the ratemaking treatment of this amount, in conjunction with other amounts, later in this chapter.

4.4.17 The total direct CIS related costs therefore to be recovered from ratepayers are $5.75 million, instead of $10.5 million originally proposed by the Company.

SIM Start-Up and Overhead Costs

4.4.18 The Company also proposed that $13.4 million be included in rate base, which is the amount allocated to the CIS project from the total SIM start-up and overhead costs.

4.4.19 The SIM start-up costs were incurred in the early stages of the SIM plan, before any particular projects were identified. As indicated above, by the SIM accounting convention all costs were lumped together under a single SIM WIP Account for both utility process improvements and costs associated with the CIS software itself. The overhead costs were incurred generally in support of all of the eventual SIM plan components. Most of these costs were incurred in the 1992 to 1996 period, prior to the development of the CIS software.

4.4.20 The methodology for this allocation was based on an apportionment of the SIM start-up costs and other costs that could not be directly attributed to specific projects. As each SIM project was closed to rate base upon completion, that project's share of indirect costs was closed to rate base as well. The Company assumed that all SIM projects would ultimately be included in rate base and that costs could therefore be proportionately allocated among them in order to provide for recovery matched to the benefits flowing from each project.

4.4.21 The Company's position was that, except for the costs directly relating to the CIS software which the Company claims it has reasonably identified, all other costs of the CIS project should be included in rate base. Many of the intervenors argued that the SIM start-up and overhead costs, being indirect costs, are derivative from and contingent on the direct project costs and that these indirect costs should have been transferred to Newco along with the direct costs of developing the CIS software.

4.4.22 It appears to the Board that the Company's claim of independence of the $13.4 million in SIM start-up and overhead costs from CIS software is merely an attempt to recover all of the remaining SIM start-up and overhead costs from ratepayers. The Board agrees with intervenors that the Company has not established that the SIM start-up and overhead costs are independent of the CIS software development.

4.4.23 In accordance with the Company's past methodology, the indirect costs should be recovered only to the extent that the direct costs associated with BPR work and analysis phase work are recoverable, and only in the same proportion that indirect costs for the CIS project bears to the direct costs of the CIS project as a whole. The Company's evidence is that the direct costs of the CIS project are $81.1 million and the indirect costs are $38.8 million. In other words the indirect costs are approximately 48% of the direct costs. On the basis of the Board's earlier allowance of $5.75 million of direct costs are recoverable for BPR and analysis work, the Board finds that 48% of this amount or $2.75 million in "pre-project" indirect costs to be recovered from ratepayers.

4.4.24 The Board therefore finds that the combined "pre-project" direct and indirect costs, before interest, to be recovered from ratepayers are $8.5 million compared to $23.9 million proposed by the Company, a difference of $15.4 million.

Interest During Construction (IDC)

4.4.25 The Company has also requested that $6.4 million be included in rate base for interest during construction on "pre-project" direct and indirect costs. This amount has been derived by applying an interest rate of prime plus 50 basis points to the monthly balances of direct and indirect costs.

4.4.26 The Board finds that interest should accrue only with respect to the direct and indirect costs that the Board has actually allowed for recovery, namely $8.5 million.

4.4.27 Since the costs of the BPR, the analysis phase and the SIM start-up and overhead costs were not costs relating to putting a capital asset into rate base, such costs are considered by the Board to be neither capital nor capitalizable. Therefore the Board finds that appropriate rate of interest is not the rate of interest normally applied to construction projects, but the Board-approved short term cost of capital for the applicable periods. For the purposes of this Decision the Board deems the difference between the Company-applied IDC rate and the Board-approved short term debt rate to be 75 basis points. On the basis of the direct and indirect costs found by the Board to be recoverable from ratepayers, the Board determines that interest charges of $2.3 million are recoverable, rather than the $6.4 million proposed by the Company, a difference of $4.1 million.

Conclusion

4.4.28 In summary, the Company proposed to close $30.3 million in rate base for CIS "pre-project" direct and indirect costs and associated interest. The Board finds that the appropriate amount for recovery from ratepayers is $10.8 million, a difference of $19.5 million.

4.4.29 A number of intervenors argued that, in accordance with the Board's statements in EBRO 495, none of the costs associated with the CIS project should be recoverable until the CIS project is complete. The Board however finds that the direct and indirect costs associated with BPR and the analysis phase work are independent of completion of the CIS software and therefore it is appropriate that they be dealt with at this time.

4.4.30 As indicated above, the Board finds that it is not appropriate that these amounts be added to rate base but rather should be expensed. For the purpose of this Decision it is convenient to recover such costs through a Z type factor adjustment to the O&M budget. Further the Board has determined that it is appropriate to recover such expenditures over a three year period. Consequently, $3.6 million shall be recovered in fiscal 2000. The balance shall be recorded in a deferral account to be disposed of in future proceedings.

4.4.31 At its next rates case the Company is directed to provide evidence that all costs of the SIM project that the Board has determined are not recoverable in rates have either been transferred to Newco or have otherwise been removed from the Company's books on a permanent basis.

4.5 COST OF SERVICE

4.5.1 The Company did not propose to transfer the CIS software to Newco until October 2000, when it is anticipated that it will be complete and its fair market value will be easier to calculate. However, the Company proposed to include costs in the test year on the grounds that the software will be completed during the test year. The Company proposed that when the software is complete it will be reasonable for Newco to charge the Company an annual service fee of $15.8 million. However, because Newco is not yet incorporated and does not yet own the CIS software, Newco will notionally pay the Company a hosting fee of $3.6 million for use of the Company's infrastructure to run the CIS software during the test year.

4.5.2 The Company's proposal further stipulated that because the CIS functions will be released in stages over the test year, the Company will be given a phase-in-credit of $4.1 million. Because the Company is under a targeted PBR plan for O&M expenses the Company proposed that the CIS Z factor should be further reduced by $0.5 million for reduced information services costs and $1.9 million for reduced customer service costs in the test year. The net result of the Company's proposal is that the total amount to be included in the CIS Z factor for the test year would be $5.7 million.

4.5.3 Ms. Williams, a witness for some of the intervenors, testified that the proposed services agreement between the Company and Newco (the "Services Agreement") is similar, although not identical, to the agreement between Union and Enlogix (the "Union/Enlogix Services Agreement") and was clearly used as a model in determining the nature and costs for the CIS services to be performed by the affiliate.

4.5.4 The Company correctly points out that although it was necessary for Union to seek prior approval from the Board for the Union/Enlogix Services Agreement, because it was an affiliate transaction under Union's Undertakings at that time, a similar approval is not required in this proceeding. Consequently it is not necessary for the Board to grant prior approval of the Services Agreement with Newco. The Board only needs to approve the cost consequences of the entire proposal, including the Services Agreement, for ratemaking purposes in the test year.

4.5.5 However, the Board notes that Services Agreement is governed by the *Affiliate Relationships Code for Gas Utilities.* The onus is on the Company to establish by independent, credible evidence that the fees to be paid to Newco for CIS services are fair market value in relation to the services being provided.

4.5.6 The Company relied heavily on the fact that the fees payable by the Company to Newco are comparable to the fees payable by Union to Enlogix under the Union/Enlogix Services Agreement. However, as some of the intervenors have pointed out, the Board has not yet determined whether in Union's case the fee structure represents fair market value to Union, it has only permitted a portion of the costs related to the Enlogix fees to be included in Union's 1999 rates and the Board has not yet approved the customer fees for Union's fiscal 2000 test year.

4.5.7 A great deal of time was spent at the hearing and many pages in written argument were used in attempting to compare the Company's proposed CIS arrangements with those for other utilities. The parties attempted to compare the services not only to those of Union but also to B.C. Gas and a variety of integrated utilities in the United States. This attempt at comparability caused the Board a number of difficulties. The basis of the evidence submitted by all of the parties was often vague and at times contradictory.

4.5.8 First, there were differences among the utilities as to the CIS functions provided, such as response time, Internet access, electronic transfer of information to and from other market participants, capability for “billing on demand”, ability to deal with proposed further unbundling of distribution services, and potential contractual restrictions on the Company’s ability to upgrade the system. Utilities of different sizes are able to take advantage of economies of scale and reduce CIS costs. Furthermore integrated utilities, such as those offering hydro and water services, in addition to the distribution of gas, are able to take advantage of economies of scope in reducing CIS costs.

4.5.9 In addition, since the CIS software is not yet complete, it is not clear what functions the CIS software will in fact perform. Therefore it is difficult to test the reasonableness of not only the $15.8 million annual fee, but also of the phase-in credit of $4.1 million, as proposed by the Company. Mr. Stephens’ evidence was that the functionality of the CIS software was 25% less than other comparable systems and therefore the proposed service fees are 25% higher than fair market value.

4.5.10 The Company’s proposal also raised the added complexity that Newco will pay the Company a $3.6 million “hosting” charge. While the Company offered some evidence that this hosting charge was equivalent to what could be expected in the open marketplace, that is, evidence that the hosting charge represented “fair market value” for the service provided, the Board agrees with intervenor criticism that the evidence is insufficient to demonstrate that the proposed hosting charge reflects full costing and indeed represents fair market value of similar services to an arm’s length party as required by the Code.

4.5.11 The Board is persuaded by the arguments of intervenors that the Company's proposal for including CIS related costs and savings in the test year is premature. At the time of the hearing, the computer software was not complete, the affiliate had not yet been incorporated, the proposed agreement had not yet been signed, and the transfer of the software will not take place until after the test year. While the Company's renewed optimism is encouraging with the completion of one phase of the project on budget and ahead of schedule, the Board requires evidence that the CIS project has been successfully completed. The Board therefore rejects the Company's request that a CIS Z factor be included in the O&M targeted PBR for the test year.

4.5.12 In EBRO 497-01, the Board indicated that it would consider that CIS costs might be an appropriate category for Z factor treatment. However, those comments were made prior to the Company submitting its revised proposal that the CIS software would be transferred to an affiliate. Having heard the evidence relating to the Company's new approach the Board has reservations whether the total fees proposed to be charged for ongoing CIS services by Newco constitute a Z factor under the existing O&M PBR regime rather than all or some of the total fee amount being part of the ongoing O&M expenses. If the Company wishes to propose a CIS Z factor in a subsequent rates cases during the term of the existing PBR regime, the Company must produce evidence to persuade the Board that any CIS related costs ought to be included as a Z factor.

5. OPERATIONS AND MAINTENANCE (O&M) COSTS

5.1 TEST YEAR O&M BUDGET

5.1.1 The evidence in EBO 179-14/15 was that the transfer of certain non-utility, non-rental programs would result in a $18.4 million reduction to the O&M budget for fiscal 1999. In the EBRO 497-01 proceeding dealing with PBR matters, the unbundled O&M budget was further adjusted downward by $9.8 million to remove the impact of one-time adjustments, such as the 1999 Board-approved Y2K and DSM expenses as well as the net impact of the rental wind down proposal. After the Settlement Proposal the resultant O&M Base upon which the PBR formula would apply was calculated to be $240.4 million.

5.1.2 In its EBRO 497-01 Decision, the Board accepted the Company's Targeted PBR Plan, in principle, subject to certain modifications. The Board required the Company to reflect the decision impact on the O&M Base of the EBO 179-14/15 Decision wherein the ABC-T program was classified as non-utility. The Company has, as of October 1, 1999, transferred the rental program to Enbridge Services Inc.

5.1.3 In the present proceeding, the Company has proposed a reduction of $24.5 million to the O&M Base. Of this amount, $21.5 million results from the removal of the rental program and $3.0 million for the ABC-T program. The resultant O&M Base would accordingly be $216.1 million before the application of the PBR formula including proposed Z factors of $14.7 million, as discussed later in this section.

Removal of Rental Program

5.1.4 IGUA, Schools, and VECC argued that the elimination of the rental program ought to be calculated on a fully costed basis, that would result in additional reductions to the unbundled O&M budget of $13.4 million. As discussed earlier in this Decision, the Board does not accept the contention by intervenors that the Board's previous references to the "no harm to ratepayers" principle in the Company's recent proceedings, dealing with the unbundling of non-utility programs, extended to the removal of allocable costs. The "no harm to ratepayers" principle applies to the removal of assets and costs to effect the removal, not to the costs previously associated with the rental program. The resources associated with the provision of services to the rental program remain with the utility. The issue in this specific instance in the Board's view is not whether the program's costs have been removed on a fully costed basis, but rather whether recognition has been given to the expectation, as alluded to by Schools, VECC, and HVAC, that additional cost reductions would occur in the utility's O&M budget due to the removal of the rental business. HVAC suggested that these potential savings should approach the level of the $13.4 million in allocable costs previously associated with the rental program.

5.1.5 In its defence, the Company argued that the impact of the Company's unbundling proposals on the O&M budget was examined in EBO 179-14/15 and subsequently updated to reflect the rental wind down and impacts of the EBRO 497-01 Decision. Also, the Company submitted that HVAC's suggestion of further rationalization of costs failed to note the up-front productivity already reflected in the O&M base and the productivity adjustment in the PBR formula.

5.1.6 The Board has difficulty accepting the Company's position. While the removal of the non-rental businesses has been discussed by the Board, this is the first time the implications of removing the rental program are being considered. When the Board reviewed the fiscal 1999 O&M budget the rental program was characterized for ratemaking purposes as ancillary. The Company's proposal in the EBO 179-14/15 proceeding was that the rental program be classified as core utility. The up-front productivity reflected in the O&M base and the productivity adjustment in the PBR formula were determined absent the removal of the rental program. Also, the restructuring proposal leading to the reduction of 173 roles was premised on a winding down of the rental program.

5.1.7 The Board concludes that, as a result of the removal of the rental program, additional rationalization of costs is both possible and likely. The difficulty is the lack of evidence to make an accurate assessment of the degree of rationalization. The Board does not accept that full rationalization will be achieved in the near future to offset the $13.4 million of allocable costs associated with the rental program, at least not in the time frame of the PBR Plan. The Board deems that half this amount or $6.7 million of savings due to rationalization will be realized by the end of the three year PBR term.

5.1.8 A further reduction of $1.1 million to the O&M base budget was argued by IGUA to reverse an upward adjustment previously made by the Company in EBRO 497-01 on the assumption that the rental program would be wound down in the utility. The Company argued that the O&M base reflecting this adjustment remains appropriate as it reflects O&M as it is required to support the ongoing operations of the utility after removing the impacts of acquiring rental capital. The Board concludes that its findings pertaining to further rationalization should equally apply in this circumstance. Therefore half of the $1.1 million or $0.6 million in savings is deemed by the Board to be realizable during the PBR period.

5.1.9 The total amount of savings in the three year PBR period, therefore, because of rationalization is deemed to be $7.3 million spread equally among the three years. For purposes of setting rates under the PBR formula, the Board therefore deems a negative Z factor of $2.4 million for the 2000 test year, which amount shall rise to negative $4.9 million and negative $7.3 million for years 2001 and 2002 respectively.

5.1.10 The Company's evidence was that certain services will be provided to the rental program on a transitional basis to ensure the smooth transition of the program for the customer and to permit an orderly transfer of the rental program to its affiliate. These services were identified as certain plant record keeping and call centre activities. It was the Company's intention to complete the transition of the rental program by March 31, 2000. In addition, the Company noted that since its affiliates do not currently have the capability to bill for a program with a customer base the size of the rental program, the Company will be providing billing services during the transition by means of the non-utility ABC-T program. IGUA argued that the $3 million elimination on account of the ABC-T program was understated given the additional activity contemplated for the program. While the Board agrees that the estimated costs in providing ABC-T service in the test year are likely understated because of the program's extended activity for part of the year, the additional costs were not reflected in the original O&M base and therefore no additional amount over the $3.0 million amount needs to be eliminated.

PBR O&M Base

5.1.11 The Company's proposed O&M Base was $240.6 million for the test year, which was revised to $240.4 million to reflect adjustments to customer additions agreed to in the Settlement Proposal.

Customer Growth

5.1.12 The customer growth variable in the PBR formula is calculated as a percentage change in the forecast average number of customer bills. The resulting customer growth variable was initially forecast as 3.69%, reduced to 3.53% as a result of the Settlement Proposal.

Inflation

5.1.13 The Company initially used an inflation forecast of 2.0% for the test year. However, the inflation variable in the PBR Formula must be derived from an unweighted consensus of the latest forecasts available in August (i.e. prior to the beginning of the test year) from the following institutions: Royal Bank of Canada, Canadian Imperial Bank of Commerce, Toronto-Dominion Bank, and the Conference Board of Canada. Based on information provided by the Company at the hearing, the unweighted consensus results in an inflation variable of 1.6%.

Z Factors

5.1.14 The Company has included the following four Z factors:

Item No.	Z Factor	($ millions)
1	DSM	6.0
2	Rate Hearing	0.4
3	Y2K	2.6
4	CIS	5.7
5	Total	14.7

5.1.15 The DSM Z factor captures expenses relating to the production of DSM savings. This amount was agreed to by the parties in the Settlement Proposal.

5.1.16 The Rate Hearing Z factor captures regulatory costs that are allocated and billed to the Company by the Board, which are not currently in the O&M Base. IGUA argued for disallowance of the incremental $0.4 million in Board costs on the grounds that a $0.5 million threshold for Z factors was not met. As discussed elsewhere in this Decision, the Board will not use at this time a specific threshold for Z factors. For the reasons provided by the Company in its evidence and argument, the Board approves the requested amount.

5.1.17 The Y2K Z factor captures the costs associated with the Y2K Program. For reasons set out elsewhere in this Decision, the Board does not approve the proposed Z factor for this expenditure. In this respect the Board has made a finding that expenditures up to the $2.6 million amount be recorded in a deferral account.

5.1.18 The CIS Z factor captures fees payable to the affiliate for use of CIS, adjusted for offsetting credits. Elsewhere in this Decision, the Board rejects the Company's proposal to recover the net CIS related costs in the test year.

5.1.19 Elsewhere in this Decision the Board deems a negative Z factor of $2.4 million for the 2000 test year related to the further rationalization of O&M costs occasioned by the removal of the rental program.

5.1.20 Elsewhere in this Decision the Board disallows the Company's request to include in rate base $30.3 million CIS "pre-project" costs; instead the Board finds that an amount of $10.8 million associated with BPR and Analysis work should be included as a Z factor type adjustment, amortized over a three year period resulting in a fiscal 2000 impact of $3.6 million.

5.1.21 In summary the Board finds a total Z factor amount of $7.6 million for the test year, instead of $14.7 million proposed by the Company, as shown below.

Item No.	Z Factor	($ millions)
1	DSM	6.0
2	Rate Hearing	0.4
3	Further rationalization of O&M costs due to removal of Rental Program	(2.4)
4	Amortization of BPR/Analysis	3.6
5	Total	7.6

2000 O&M Budget

5.1.22 Based on the Board's findings in this Decision on the base O&M, PBR factors and Z factors, the Board calculates the O&M budget for the test year to be $232.5 million as shown below.

Application of PBR Formula for Test Year 2000 O&M Expenses
Test Year O&M Expenses = [Base Year O&M[a] x (1 + (customer growth[b] - productivity[c])) x (1 + inflation[d])] ± Z factors[e] = [($240.4 million - $24.5 million) x (1 + (0.0353 - 0.011)) x (1 + 0.016)] + $7.6 million = $232.5 million
Notes: a Base Year O&M as per ECG Argument-in-Chief = $240.4 million - $24.5 million = $216.1million b customer growth = 3.53% per Settlement Proposal c productivity = 1.1% per EBRO 497-01 d inflation = 1.6% per consensus forecast e Z factors (in millions) = $6.0 (DSM) + $0.4 (Rate Hearing) + $3.6 (BPR and Analysis) - $2.4 (further rationalization of O&M) = $7.6

5.2 MONITORING AND REPORTING REQUIREMENTS

5.2.1 In its EBRO 497-01 Decision, the Board indicated that it would monitor the performance of the Company during the course of the Targeted O&M PBR Plan by monitoring the Service Quality Indicators (SQIs) results during the Company's main rates cases. In addition to the reporting of SQIs results, the Company proposed to continue the existing monitoring and reporting process. The existing process includes monitoring reports that are filed with the Board's Energy Returns Officer (ERO) on a quarterly basis. The Company would also continue to file in its annual rate filings historical and bridge year information. The Company believed that this would provide sufficient information to the Board to allow for effective monitoring during the PBR Plan.

5.2.2 The issue for intervenors is the perceived inadequacy of the information to be filed in rate cases. The O&M expenses would be reported on a one line basis, not line by line to allow comparison on a per component basis, including non-utility eliminations, from the base approved by the Board. Intervenors argued that unless the information is reported in a line by line format comparable to the unbundled budget from which the O&M budget is derived, their ability to monitor performance for purposes of assessing whether conditions exist for an off ramp during the PBR term, rebasing at the end of the term or monitoring affiliate transactions is being compromised. Intervenors also argued that the information filed with the ERO should be made available to the parties.

5.2.3 In the Board's view, it is clear from the Board's EBRO 497-01 Decision that its findings regarding monitoring and reporting pertained only to the service quality indicators. The arguments by intervenors in the current case sought to expand the scope of the monitoring and reporting requirements for the Company. The Board is concerned that acceptance of the intervenors' suggestions will compromise the PBR process, before it has been given a chance to begin; it will inevitably result in a line by line scrutiny of the O&M budget as if under cost of service regulation. In EBRO 497-01 the Board accepted the suggestion that any party could ask for an off ramp. However, the off ramp provision is not to be construed as a license for intervenors to request and receive information as if nothing has changed from cost of service regulation. Using such information for purposes of reviewing and addressing issues in annual rate cases would be contrary to the incentive and regulatory efficiency reasons for establishing a PBR plan in the first place. Receiving such information only for the sake of receiving it and not for probative, ratemaking purposes simply adds costs and potential complexities.

5.2.4 The information provided to the ERO contains current year estimates of expected financial performance, including an estimate of equity returns. The Board finds no compelling reason to make the quarterly information filed with the ERO available to parties. The Board is puzzled as to how such information could be used to advance regulatory efficiency since the parties will, in any event, receive estimates for the current year annually as part of the Company's rate case filing.

5.2.5 The Board finds that the filing of information with the Board's Energy Returns Officer and the provision of information in rates cases as proposed by the Company accomplishes a fair balance of preserving the incentive power of the Company's targeted O&M PBR plan and accomplishing the other Board objectives set out in the Board's *Draft Policy on PBR*. At the time of rebasing, the parties will have an opportunity to request that appropriate information be provided to allow a line by line comparison with the base budget. In the meantime, the Board expects the Company to file the financial information with the Board's Energy Returns Officer on a timely basis. The Board also expects that the financial monitoring issue related to the O&M expense will not be revisited for the duration of the Company's current PBR plan.

Service Quality Indicators (SQIs)

5.2.6 In the EBRO 497-01 proceeding, the Board accepted five SQIs, or performance measures, to be filed as part of the Company's annual rate cases in order to monitor its performance during the life of the Targeted O&M PBR Plan. The five SQIs are: telephone service factor, meter reading, emergency response time, distribution system integrity survey, and gas utilization infractions. In the same proceeding, the Board directed the Company to propose some quantitative targets with respect to the

Company’s Distribution System Integrity Survey. This survey consists of the Leak Survey Program and the Corrosion Survey Program.

5.2.7 In the current proceeding, the Company stated that, for the Leak Survey Program, the overall program schedule is made up of a number of surveys with different frequencies. The frequency cycles are based on pipe material, material age, gas pressure, history of leaks, and local geography. For these reasons, the number of survey areas will vary from year to year. The Corrosion Survey Program is intended to ensure that corrosion protection systems are working and that corrosion surveys are completed on an annual basis. One of the principles of the survey is that corrosion protection personnel must determine that an entire corrosion area is properly protected. The result is that the number of areas remains constant from one year to the next. The current number of corrosion survey areas is 9,615. All 9,615 areas, which correspond to 100% of the Company’s franchise area, will be surveyed in the test year. The Board finds the information provided by the Company to be responsive to the Board's direction in EBRO 497-01.

6. OTHER ISSUES

6.1 VOLUME FORECAST - AVERAGE USE FOR RATE 1 AND RATE 6

6.1.1 The average use per customer for the test year was forecast by the Company to decline by 92 m^3 for Rate 1 and by 679 m^3 for Rate 6. CAC, IGUA and Schools noted that the forecast declines in both rate classifications are unprecedented, that the Company has a history of underforecasting average use and that the Board should find higher levels of average use.

6.1.2 The Board agrees that a review of the Company's forecast performance over several years leads to the conclusion that there has been, on balance, an underestimation of average use for the two rate classifications. Given the evidence that the methodology applied by the Company for estimating average use in the test year is consistent with past practice, the Board understands intervenors' conclusions that the underforecasting bias will likely persist. Further, the Company's argument that its 0.26% variance record for total volumes on a normalized basis since 1991 is without merit. An underestimation in higher margin rate classifications and an overestimation in lower margin rate classifications do not offset each other from a revenue requirement perspective.

6.1.3 The Board however notes that during the hearing the Company provided, on request, the most recent 1999 experience for Rate 1 and Rate 6. Intervenors did not comment on the report that year-to-date Rate 6 average use is tracking with the 1999 Estimate and the year to date results for residential average use per customer show that there has been a significant decline in average use even below levels assumed in the 2000 Budget.

6.1.4 On balance the Board accepts the Company's average use forecasts for setting rates in the test year. However, in light of concerns over the Company's forecasting record, should the normalized actual use per customer for Rate 1 and Rate 6 in fiscal year 2000 turn out to be appreciably higher than forecast, thereby confirming intervenors' views, the Board expects the Company to review its forecasting methodology with the view to correcting underforecasting biases.

6.2 TRANSACTIONAL SERVICES FORECAST

6.2.1 Transactional services are provided to ex-franchise customers and include short cycle peak storage, off-peak storage, gas loans, exchanges, and assignments of transportation capacity. The primary objective is to maximize the realizable value of the Company's physical and contractual storage and transportation assets. Under the existing two-tiered sharing ratio, the shareholder receives a 10% share of the Company's forecast Net Revenue (Gross Margin minus Marginal O&M expenses) and is provided with an incentive share of 25% of the amount in excess of the forecast. For the test year, the forecast of Gross Margin is $4.5 million and Marginal O&M expenses is $0.57 million, resulting in Net Revenue of $3.93 million. The ratepayers benefit up-front by 90% of that amount, or $3.5 million. The amount by which the actual Gross Margin for the test year exceeds the amount of $4.5 million will be recorded in the 2000 Transactional Services Deferral Account (TSDA). The Company proposed that any credit balance in the 2000 TSDA continue to be shared on a 75/25 basis between the ratepayers and the shareholder respectively. A negative variance in Gross Margin (i.e. a debit balance in the 2000 TSDA) would continue to be solely for the account of the shareholder.

6.2.2 Several intervenors argued that the two-tiered sharing regime should be replaced by a single ratepayer/shareholder ratio regime of 90/10. In support of that position, intervenors noted that this single ratio would eliminate the Company's incentive to underforecast, it would eliminate annual debates, and it would produce more equitable results. Further it was argued that the differentiation is not consistent with, and is unnecessary, under a PBR regime.

6.2.3 The Board notes that the marginal O&M costs of the program are not included in the overall O&M base under PBR. Therefore, the Board agrees with the Company that the program ought to be viewed on a stand-alone basis, independent from the incentive inherent in the PBR mechanism.

6.2.4 The Board agrees that as a general principle a single sharing ratio would eliminate incentives to underforecast, and would reduce or even eliminate annual debates. However, in the Board’s view the Company’s response that a credit balance in the account is positive evidence that the incentive mechanism inherent in the two-tiered sharing mechanism is working as intended does not really address intervenors’ concerns.

6.2.5 In the Board's view, the proposed single ratio would provide less incentive for the Company to maximize transactional services revenues. Although the shareholder benefits from that, ratepayers benefit to a much greater extent. Notably the benefits to the ratepayers arise without any risks if the deferral account is in negative balance. A single sharing ratio may raise issues of symmetry between risks and rewards. Also, intervenors always have the opportunity to test the Company's forecast as is the case with other revenue or cost of service items.

6.2.6 On balance, the Board is not persuaded at this time to change the existing two-tiered sharing ratios as proposed by intervenors.

6.2.7 The Board notes that it was agreed by the parties that this issue be dealt with in argument only. The Board wishes to comment on the concerns expressed by intervenors on the Company's statement in its Argument-in-Chief that "However, no party cross-examined Mr. Rahn, the Company's scheduled witness, and therefore his evidence in this regard ... was not challenged". As certain intervenors pointed out, the issue to have been brought forward was one of principle, not the specifics contained in Mr. Rahn's prefiled evidence. Intervenors agreed to leave the issue for argument on the general invitation by the Board as to what issues need not go to cross-examination. The Board had hoped that the Company's statement in Argument-in-Chief was unintended. However, based on the Company's Reply Argument, it does not appear to be so. The Board finds the Company's statement regrettable. It is contrary to striving for regulatory efficiencies and developing good faith, objectives which the Company so often claims to endorse.

6.3 YEAR 2000 (Y2K) COSTS

6.3.1 In its EBRO 497 Decision the Board authorized the establishment of the 1999 Y2K Deferral Account (Y2KDA) and directed that the balance in the 1998 Y2KDA be brought forward as the opening balance in the 1999 Y2K Variance Account (Y2KVA). The Board further directed that any amount in the 1999 Y2KVA, brought forward for disposition in the future, be the difference between the sum of the amount carried over from fiscal 1998 and any amount recorded during fiscal 1999, net of $6.2 million that was authorized for inclusion in rates. The Company sought the Board's approval to recover in the test year the forecast balance (as of September 30, 1999) in the 1999 Y2KVA of $8.327 million less the amount of $0.76 million of fiscal 1998 Y2K costs that were allocated to non-utility and ancillary programs, for a net total of $7.567 million.

6.3.2 During the oral hearing, an issue arose as to the appropriate allocation of the balance in the 1998 Y2KDA, which was included as the opening balance in the 1999 Y2KVA. The Company's witness agreed that some portion of the opening balance of the 1999 Y2KVA, representing the 1998 Y2K costs incurred on account of non-utility and ancillary programs, should be allocated to such programs. In the EBRO 497 proceeding, the Company filed a response to an undertaking that specified an allocation of approximately 17% to non-utility and ancillary programs. Based upon actual Y2K expenditures of $4.5 million in fiscal 1998, $0.76 million of the 1998 Y2K costs that are included in the 1999 Y2KVA should be allocated to non-utility and ancillary programs.

6.3.3 For test year rates, the Company proposed a Z factor of $2.6 million for O&M costs related to the Y2K program. This amount represents the Company's forecast of the O&M costs of the Y2K program. The forecast of O&M costs for the test year is comprised of the costs associated with salaries, benefits, contractors, conversion automation, testing and implementation, business unit conversion and testing, business continuity, and infrastructure deployment. Over half of the $2.6 million would be incurred in respect of salaries, benefits, and contractors. The costs of salaries and benefits (totalling $1.1 million) are those viewed by the Company to be incremental amounts, paid by the Y2K program. This includes approved backfill positions, staff that were not included in the 1999 Y2K budget, on-call staff, and co-op students. Where an employee has been backfilled, the Y2K program incurs the cost of the backfilled position. For test year rates, the Company also sought approval of $0.5 million in Y2K capital costs. Of the $0.5 million, about $0.2 million is attributable to non-IT infrastructure, such as gas distribution equipment, environmental controls, SCADA, and other field technology, and $0.3 million for purchases of equipment, such as back-up generators and satellite phones.

6.3.4 The Company also proposed to establish a 2000 Y2K variance account to capture the variance between the forecast amount of $2.6 million, proposed as the Y2K Z factor, and the actual incremental Y2K program costs that are incurred.

6.3.5 A number of intervenors took positions on the Company’s proposals. They noted the Board's finding in EBRO 497, in that shareholder responsibility would be an issue, and argued that all or part of the 1999 Y2K recorded costs should be disallowed. Various suggestions were made regarding the Company’s proposals for the test year, including outright denial of the proposed Z factor and the proposed 2000 Y2K variance account, denial of the proposed Z factor and replacement of the requested variance account with a deferral account, and capping the variance account at $2.6 million.

There was also a suggestion that Y2K costs not yet recovered should not be recoverable until the Company proves that there have been no negative consequences to ratepayers because of the Y2K problem. Further, certain intervenors argued that the proposed 1999 Y2K balance should be adjusted to fully reflect an appropriate apportionment for non-utility and ancillary activities.

6.3.6 The Board notes that the Company agreed that a 17% reduction to the 1998 Y2K deferral account balance may be made by the Board on account of non-utility eliminations and ancillary program activities. The Board directs the Company to make this adjustment as part of its draft Rate Order filings with the Board. However, the Board is not persuaded by intervenor arguments that a reduction to the 1999 Y2K balance by a further $0.65 million related to non-utility and ancillary program costs is warranted. For such further reduction to take place, the Board agrees with the Company that total Y2K costs in 1999 (level allowed in rates plus amount booked in the deferral account) would have to exceed the $11.7 million level proposed by the Company in EBRO 497. The evidence in the current proceeding indicated that this threshold had not been exceeded.

6.3.7 Intervenors argued that non-regulated companies do not have recourse to recovering their Y2K costs as the Company does. This may or may not be so. The issue in the Board’s view is whether the Company’s expenditures, previously incurred and deferred and for which recovery is requested, have been prudently incurred. Going forward, the issue is one of assessing whether the expenditures will be incurred as expected. An overriding consideration, in the Board’s view, is whether the substantial expenditures made by the Company on the Y2K program have secured safe and reliable service.

6.3.8 With respect to expenditures already incurred, one area where the Board expressed concern in its EBRO 497 Decision was the lateness of the Company's actions that may have resulted in higher costs. However, based on the evidence and arguments the Board has been persuaded that no costs should be disallowed in that regard. However, the Board has viewed and continues to view the Y2K issue as an unusual one, with no precedent for guidance. The closest activity specific to the Company's circumstances is its expenditures on CIS. In that case the Board chose to defer assessment and recovery of CIS expenditures over the years until such time as the project proved to be operational. In the case of Y2K, total recovery from ratepayers of the full amount would hold the shareholder harmless in the event that the Company's actions in addressing the Y2K issue lead to unwarranted customer service impacts where the Company may be viewed to be responsible.

6.3.9 There needs to be in the Board's view a practical regulatory mechanism for holding the shareholder responsible should this be the case, without the need to engage in complex discussions pertaining to out of period regulatory issues. The Board therefore will permit the recovery of half of the 1999 deferral/variance account balance at this time. The remaining balance shall be recorded as the opening balance in the 2000 Y2K deferral account for disposition at the next rate case upon satisfactory evidence that the Y2K issue has been addressed with no material negative service consequences to customers that can be reasonably be traced to Company management.

6.3.10 Going forward, the Board is persuaded that some additional expenditures will have to be made to complete the Y2K program. The Board notes the Company's confidence in its oral testimony that it believes it can manage the remaining Y2K issues with a budget of $2.6 million. Given the Company's expressed confidence and the relative magnitude of the amount at issue, the Board directs that the amount recoverable from ratepayers in year 2000 be capped at $2.6 million, and also be recorded in the 2000 deferral account. The disposition of the recorded amount will be based on the prudence of expenditures and, as with the 1999 partial balance carried forward to the 2000 account, upon satisfactory evidence that the Y2K issue has been addressed with no material negative service consequences to customers that can be reasonably be traced to Company management.

6.4 2000 CLASS ACTION SUIT DEFERRAL ACCOUNT (CASDA)

6.4.1 The purpose of the 2000 CASDA is to record litigation costs incurred by the Company in its defence of the lawsuit which challenges the Company's late payment penalties. The Supreme Court of Canada has returned this case to the trial court for the determination of the remaining issues and for proceedings in accordance with the *Class Proceedings Act, 1992*. The Board has previously authorized, through rate decisions and accounting orders, a series of deferral accounts for costs incurred in prior years in the defence of this litigation. Consistent with this practice, the Company sought Board approval to continue the deferral account for 2000.

6.4.2 IGUA and Schools argued that the Company's proposal is inconsistent with the parameters of the PBR plan, in that litigation costs, by the Company's own admission in EBRO 497-01, would not be a Z factor. The Board accepts the Company's argument that its reference to litigation costs in EBRO 497-01 was in the context of an example of a potential judgement against the Company in relation to the environmental remediation costs of manufactured gas plant sites and it did not cover the specific litigation costs at issue here. The Board also accepts that the Company in EBRO 497-01 specifically noted that the existing deferral/variance accounts would be continued separately from the Z factors which form part of the approved PBR regime.

6.4.3 CAC argued that a materiality threshold of $0.5 million should apply which would preclude the continuation of this deferral account. The Board is neither prepared to accept the specific threshold suggested by CAC at this time, nor to accept the Company's proposal contained in its Reply Argument in this proceeding, initially proposed and rejected in EBRO 497-01, for a generic Z factor deferral account.

6.4.4 The Board finds no persuasive reasons to change the status quo. The Company is therefore authorized to continue its CASDA deferral account.

6.5 PROPOSED RATE 125

6.5.1 The Company proposed to introduce Rate 125 in the test year to respond to the emerging opportunities for natural gas fueled cogeneration and power generation. The Company noted that several cogeneration projects are already in the planning stage and at least six cogeneration and/or power generation projects are expected to come on-stream in the Company's franchise area in the period from 2001 to 2004. The total incremental throughput associated with these projects was estimated to add 25% to the Company's existing deliveries.

6.5.2 The proposed Rate 125 would be available to all customers whose annual consumption exceeds 200 10^6m^3 per year and who operate at a year-round load factor of at least 90%. Rate 125 would also provide unbundled distribution service from the Company's city gate to the customer's premises but would exclude storage, load balancing or other upstream transportation services. While it is envisaged that most customers who will take service under Rate 125 will be cogeneration plants, the applicability of Rate 125 would not be limited to any particular end-use customer.

6.5.3 While the Company does not expect any customers to take service under Rate 125 in the test year, it has requested Board approval of Rate 125 at this time because projects that would qualify for Rate 125 require some assurance regarding the level of applicable rates for feasibility assessment before proceeding beyond the planning stage. The Company pointed out that such projects typically require a lead-time of 18 to 24 months in order to meet their planning cycle.

6.5.4 The Company noted that the introduction of Rate 125 is expected to have little or no impact on other rate classes. Currently, the Company has only one firm Rate 115 customer that meets the applicability criteria for Rate 125 but this customer is not expected to migrate to Rate 125 until such time the Company implements unbundled rates and services. This migration will increase the unit cost of distribution service, under Rate 115, from 0.71 cents/m^3 to 0.79 cents/m^3, an increase of 11%. The impact on the total bill for a typical bundled T-Service customer in Rate 115 represents an increase of approximately 3%. However, if all forecast loads come on-line for Rate 125 thereby increasing total annual deliveries by 25%, the Company expects that the unit cost for transmission mains for Rate 115 customers will decline by approximately 8.4%.

6.5.5 The Company's proposal was supported by IGUA, Pollution Probe, Schools, and TCPL. CAC and OAPPA opposed the proposal. OAPPA opposed it on the grounds it would be premature to approve the proposal now since no customers are expected to take service in the test year. OAAPA also contended that the proposed rate is an unbundled rate and as such provides the benefits of unbundling to selective customers.

CAC argued that the proposal should be deferred and considered as part of the Company's unbundling proposals. CAC also questioned the reliance on distribution rate levels for determining the feasibility of power projects. Further, it stated that the Company has not presented evidence on the likelihood of potential bypass.

6.5.6 While there is no expectation that this rate classification will have any customers in the test year, this is not in the Board's view determinative. Further the Board notes that no harm has been demonstrated to any stakeholder by the introduction of the proposed rate now. The Board is satisfied that the issue of bypass has been adequately addressed by the Company in its testimony and argument. In light of the above and given the substantial potential benefits to the provincial economy from cogeneration and for the existing utility customers, the Board approves the Company's proposal for introducing Rate 125.

7. COSTS AND COMPLETION OF THE PROCEEDING

7.1 COST AWARDS

7.1.1 The following parties applied for an award of costs:

- Alliance of Manufacturers & Exporters Canada (AMEC)
- Canadian Association of Energy Service Companies (CAESCO)
- Consumers' Association of Canada (CAC)
- Energy Probe Foundation (Energy Probe)
- Green Energy Coalition (GEC)
- Heating, Ventilation and Air Conditioning Contractors Coalition Inc. (HVAC)
- Industrial Gas Users Association (IGUA)
- Toronto Catholic District School Board and the Ontario Association of School Business Officials (Schools)
- Ontario Association of Physical Plant Administrators (OAPPA)
- Pollution Probe Foundation (Pollution Probe)
- Vulnerable Energy Consumers Coalition (VECC)

7.1.2 In order to expedite the issuance of the Board's Decision regarding 2000 rates, and to give the Board an opportunity to review the cost applications and related matters, the Board will not address cost claims at this time. A supplementary decision on cost awards will be issued in due course.

7.1.3 The Board directs the Company to pay the Board's costs of, and incidental to, this proceeding upon receipt of the Board's invoice.

7.2 REVENUE REQUIREMENT AND DRAFT RATE ORDER

7.2.1 The rates currently in effect are those approved by the Board in its RP-1999-0001 Interim Rate Order, effective October 1, 1999, incorporating changes to reflect the higher cost of gas forecast, as agreed to by the parties in the Settlement Proposal and approved by the Board during this proceeding. Based on these rates, the Company calculated a test year revenue deficiency of $71.8 million after incorporation of the agreed upon changes pursuant to the Settlement Proposal. Included in that calculation is a rate of return of 9.51% last approved by the Board in the EBRO 497 rates case. The Board finds an overall revenue deficiency of $28.1 million, as shown in Appendix A. This level of revenue deficiency incorporates a rate of return on common equity of 9.73%, which results from the application of the Board's *Draft Guidelines on a Formula Based Return on Common Equity for Regulated Utilities*.

7.2.2 The Board authorizes the Company to adjust its rates as a result of this Decision effective October 1, 1999. The Company is expected to adjust the cost allocations to the different rate classes so that the revenue-to-cost ratios are not materially different from those proposed. The Board expects the Company to implement the new rates as soon as possible but not later than February 1, 2000. However, given the lateness of this proceeding vis a vis the commencement of the Company's fiscal year 2000, the Board will not permit the recovery of any charges arising from the Board-approved revenue deficiency through retroactive one-time adjustments. The Board therefore directs the Company to recover the Board-approved revenue deficiency from the implementation date to the end of the test year. However, the portion of the Board-approved revenue deficiency associated with the period from the effective date of October 1, 1999 to the implementation date (e.g. February 1, 2000) shall be recovered through a rate rider.

7.2.3 The Company is directed to submit to the Board, within 10 business days of the date of release of this Decision, a Draft Rate Order reflecting the Board's findings, to be accompanied by the following:

1. proposed final rate schedules with appropriate supporting documentation;

2. updated deferral/variance account balances and interest calculations;

3. information/calculation of one time adjustments to reflect the disposition of the deferral/variance account balances;

4. draft accounting orders and entries for the new and continuing deferral/variance accounts;

5. a listing of the Board's directives pertaining to future rate filings; and

6. drafts of the proposed notices to customers which shall accompany the first customer bill following the implementation date of the new rates.

7.2.4 The draft schedules and supporting documentation will be available at the Board's offices. Parties wishing to comment on proposed final rates may do so no later than 5 business days following the date on which the Board receives the draft material. To facilitate this process the Company shall provide all intervenors of record in this proceeding with a facsimile copy of its transmittal letter.

DATED at Toronto December 16, 1999

Paul Vlahos
Presiding Member

Sheila K. Halladay
Member