E.B.R.O. 497

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for an order or orders approving rates to be charged for the sale, distribution, transmission and storage of gas for its 1999 fiscal year.

BEFORE: H.G. Morrison
Presiding Member

P. Vlahos
Member

R. M. R. Higgin
Member

DECISION WITH REASONS

August 31, 1998

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1 INTRODUCTION

1.1 THE APPLICATION AND PROCEEDING

1.1.1 The Consumers' Gas Company Ltd. ("Consumers Gas" or "the Company") filed an Application with the Ontario Energy Board ("the Board") dated January 8, 1998 ("the Application"), for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for Consumers Gas' 1999 fiscal year commencing October 1, 1998 ("the test year"). The Board assigned file number E.B.R.O. 497 to the Application.

1.1.2 Although not dealt with in this Decision, the following other applications accompanied the Application:

- As part of its Application for the 1999 test year, Consumers Gas applied for an incentive mechanism in relation to the Operation and Maintenance component of cost of service effective during fiscal years 2000 through 2002, and an incentive mechanism in relation to Demand Side Management effective fiscal year 2000. The Board has assigned file number E.B.R.O. 497-01 to this portion of the Application.

- Pursuant to its Undertakings given to the Lieutenant Governor in Council ("Undertakings"), Consumers Gas applied to the Board for all necessary approvals for transactions related to the transfer of certain customer information systems ("CIS") to an affiliate effective as of, or prior to, October 1, 1998. Consumers Gas also requested approval, under the Undertakings, for transactions between itself and the affiliate related to billing and related customer services to be provided by the affiliate to Consumers Gas and approval to provide related management and administrative services by Consumers Gas to the affiliate. The Board assigned file number E.B.O. 179-14 to this portion of the proceeding.

- Pursuant to the Undertakings, Consumers Gas also applied to the Board for all necessary approvals for transactions related to the transfer of certain businesses and activities to one or more affiliates effective as of, or prior to, October 1, 1999. These businesses and activities include merchandise sales and finance, appliance rentals, appliance service, and heating parts replacement. The Board assigned file number E.B.O. 179-15 to this portion of the proceeding.

1.1.3 The Board issued a Notice of Application dated January 27, 1998. In Procedural Order No. 1 dated February 25, 1998, the Board set out various directions relating to the orders and approvals sought by the Company in E.B.R.O. 497 and E.B.O. 179-14, and stated that a procedural order relating to E.B.R.O. 497-01 and E.B.O. 179-15 would be issued in due course. Pursuant to Procedural Order No. 1, a number of events occurred. A technical conference was held on March 9, 1998. On March 11, 1998, an issues conference was held for the purpose of developing an issues list. The proposed issues list was presented to the Board for its consideration on March 12, 1998. Under Procedural Order No. 1, dates were set for the filing of interrogatories and responses, and for the submission of intervenor and Board Staff evidence. The Order also made provision for the Settlement Conference which commenced on May 8, 1998.

1.1.4 On March 13, 1998, Procedural Order No. 2 was issued to finalize the Issues List for E.B.R.O. 497 and E.B.O. 179-14. Procedural Order No. 2 also revised the dates for the filing of interrogatories and responses. By letter dated March 24, 1998, the Company informed the Board and intervenors that the affiliate transactions for which approval was sought in E.B.O. 179-14 would not take place in the 1999 test year, and that the Company had decided to defer the hearing of that application to be dealt with together with E.B.R.O. 497-01 and E.B.O. 179-15. By letter dated May 28, 1998 the

Company informed the Board and intervenors that, in regard to E.B.O 179-15, it expected to transfer certain utility and non-utility businesses to Consumersfirst Ltd. ("Consumersfirst"), a non-subsidiary affiliate. However, the appliance rental business would remain in the Company and would be wound down starting October 1, 1999 (no new rental customers would be accepted and existing rental units would not be renewed after that date). The appliance service portion of the rental business would also be transferred to Consumersfirst. The Company also advised in the above letter that it would be amending its E.B.O. 179-14 application to exclude CIS matters and to include the transactions associated with only that information software which is integral to the operations of the businesses to be transferred to Consumersfirst.

1.1.5 E.B.R.O. 497-01, E.B.O. 179-14, and E.B.O. 179-15 will be dealt with as Phase II of this proceeding. The Board received a proposed issues list for Phase II on August 13, 1998.

1.1.6 The present Decision deals only with the main rates application, E.B.R.O. 497.

1.1.7 The oral hearing commenced on June 1, 1998 and lasted 18 days ending on June 26, 1998. The argument phase was completed on July 31, 1998.

1.1.8 According to the Company's initial filing, dated February 25, 1998, an overall gross revenue deficiency of approximately $53.1 million would exist in fiscal 1999, based on the rates approved in E.B.R.O. 495. Four updates were submitted to the Company's initial filing.

1.1.9 The first update, Impact Statement No. 1 dated April 3, 1998, reduced the claimed gross revenue deficiency by $5.1 million to $48.0 million. The change was primarily due to a correction to the allowance for gas in storage and to the delay in the transfer date of the CIS to an affiliate.

1.1.10 As a result of a mid-year review of the fiscal 1999 volumetric forecast, the second update, Impact Statement No. 2 dated May 11, 1998, reduced the gross revenue deficiency by $1.6 million to $46.4 million. The change was attributed mainly to lower than anticipated levels of customer participation in Agency Billing and

Collection Transportation Service ("ABC T-service"). Impact Statement No. 2 utilized the rates approved in E.B.R.O. 495, as did Impact Statement No. 1. Due to time constraints, the Company did not reflect the newer rates (higher gas costs) effective May 1, 1998 pursuant to E.B.R.O. 495-01.

1.1.11 The third update, Impact Statement No. 3 dated May 28, 1998, increased the gross revenue deficiency by $88.3 million to $134.7 million. The change in gross deficiency resulted mainly from updated gas commodity cost forecasts, storage and transportation charges and tolls approved by the Board in E.B.R.O. 495-01.

1.1.12 The fourth and final update, Impact Statement No. 4 dated June 16, 1998, decreased the gross revenue deficiency by $0.5 million to $134.2 million. The updated gross revenue deficiency reflected the actual cost of issuing certain debt instruments.

1.1.13 Of the total gross revenue deficiency, approximately $31 million is attributed to distribution operations and the balance to gas supply (commodity and load balancing). The $31 million gross revenue deficiency from distribution includes the costs and revenues of the Company's ancillary programs.

1.2 THE SETTLEMENT PROPOSAL

1.2.1 A Settlement Conference was held by the parties commencing May 8, 1998. The final result of the Conference, the Settlement Proposal, was presented to the Board on May 22, 1998. Nineteen parties participated in the Settlement Conference. Board Staff, while present at the Settlement Conference, was not a party to the Settlement Proposal.

1.2.2 The Board reviewed the prefiled evidence as well as the rationale provided in the Settlement Proposal for settled issues. The Board advised the parties that it accepted the Settlement Proposal, subject to clarification of certain issues. As a result of the Board's inquiries, certain amendments were made to the Settlement Proposal document during the hearing.

1.2.3 The Board reminded parties that it has the authority to take administrative notice of significant external events which may affect the settled issues. The Board also noted that there may be situations where, due to connectivity, a settled issue may be affected by the Board's findings on a non-settled issue.

1.2.4 The Settlement Proposal is attached as Appendix E to this Decision. The impact of the Settlement Proposal reduced the gross revenue deficiency from that originally filed by $4.1 million, subsequently adjusted to $3.4 million because of various updates during the hearing. The details are shown in Appendices A to D.

1.2.5 Parties reached a complete settlement of some issues; others were settled to the satisfaction of only some of the parties, or partially settled to the satisfaction of all parties. The Board's Decision generally addresses issues which were not settled, and issues for which the settlement was not complete. In addition, the Board makes some specific findings necessary to the completeness of the Decision.

1.3 PARTIES TO THE PROCEEDING

1.3.1 Thirty-six parties intervened. Eighteen intervenors filed interrogatories. Below is a list of parties, including the Company, and their representatives who participated actively in the oral hearing by cross-examining or filing argument.

The Consumers Gas Company Ltd. ("Consumers Gas")	Jerry Farrell Fred Cass Helen Soudek
Alliance Gas Management Inc. (" Alliance Gas")	Brian Dingwall
Alliance of Manufacturers and Exporters, Canada ("the Alliance")	Beth Symes
Association of Municipalities of Ontario ("AMO")/ECNG Inc. ("ECNG")	Peter Scully
Coalition for Efficient Energy Distribution ("CEED")	Judy Goldring George Vegh

Consumers Association of Canada ("CAC")	Robert Warren
Consumersfirst Ltd. ("Consumersfirst")	David Purdy
Energy Probe Foundation ("Energy Probe")	Tom Adams Mark Mattson
Green Energy Coalition ("GEC")	David Poch
The Heating, Ventilation and Air Conditioning Contractors Coalition Inc. ("HVAC")	Ian Mondrow
Industrial Gas Users Association ("IGUA")	Peter Thompson
Ontario Association of Physical Plant Administrators ("OAPPA")	Michael Morrison
Ontario Association of School Board Officials\Metropolitan Toronto Separate School Board ("the Schools")	Thomas Brett
Ontario Coalition Against Poverty ("OCAP")	Michael Janigan
Pollution Probe Foundation ("Pollution Probe")	Murray Klippenstein
Union Energy Inc ("Union Energy")	Donald Rogers
Canadian Association of Energy Service Companies ("CAESCO")	Thomas Brett
Coalition of Eastern Natural Gas Aggregators and Sellers ("CENGAS")	Richard Perdue

Board Staff were represented by Kenneth Rosenberg.

1.3.2 The Consumers Gas' employees who appeared as witnesses are shown below.

A. M. Bagnall	Director, Accounting Policy
F. Botticella	Manager, Rental Products
R.A. Bourke	Manager, Regulatory Accounting
F. A. Brennan	Manager, Gas Supply Planning and Regulatory Projects
M. F. Butler	Director, Market Development
G. W. Dann	Director, Gas Supply Services
M.P. Duguay	Manager, Rate Research and Design
J.P. Gould	Director, Budgets and Forecasts
I. Gunel	Group Manager, DSM Programs
J.A. Holder	Vice President, Energy Services
R. J. Huggard	Vice President, Retail Services
D.M.S. Kent	Vice President, Information Services
S.F. Kokotka	Manager, NGV Business Development
H. M. Lavergne	Vice President, Regulatory Affairs
M.P. Levac	Manager, Upstream Regulatory Proceedings
W. Lomax	Manager, Financial Studies
W.G. Martin	Director, Management Services, Information Services
S. H. McGill	Manager, Customer Support
M. J. Mees	Manager, Volume and O&M Budgets
S.D. Noble	Manager, Financial Reporting
J.C. Parker	Group Manager, Financial Products and Services

J. A. Parr	Vice President, Human Resources
T.R. Pasher	Director, Corporate Year 2000 Programs
H.A.E. Reynolds	Supervisor, Management Accounting Policy
R.F. Riccio	Manager, Financial Statement Forecasts
N.W. Ryckman	Portfolio Manager, System Expansion
R.L. Sawatzky	Director, Compensation Benefits
G.L. Sevick	Senior Vice President, Distribution Operations
A.P. Skalski	Group Manager, Residential Marketing
D.R. Small	Manager, Gas Costs and Budgets
W.B. Taylor	Director, Financial and Economic Studies
A.C. Wilson	Director, Market Planning and Evaluation
R.C. Wood	Vice President, Customer Support Services
B. J. Vari	Plant Accountant

1.3.3 In addition, Consumers Gas called the following witnesses:

B.W. Boyle	Manager, Corporate Finance, IPL Energy Inc.
R.G. Parker	Partner, Deloitte & Touche, National Computer Assurance Services
D. Nichols	Vice President, Tellus Institute

1.3.4 GEC filed evidence prepared by C. Neme of Vermont Energy Investment Corporation and P.H. Mosenthal of Optimal Energy. They were not required to appear at the hearing.

1.3.5 Board Staff filed evidence prepared by D.P. Dungan of the University of Toronto. He was not required to appear at the hearing.

1.3.6 Consumersfirst called its employee J. J. Sheinfield, Director of Commodity Services.

1.3.7 The Board received three letters requesting observer status from other organizations and individuals.

1.3.8 The Board received two letters of comment expressing concerns regarding the Company's request to increase rates.

1.3.9 Copies of all the evidence, exhibits and argument filed in the proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices.

1.3.10 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 ANCILLARY PROGRAMS AND NON-UTILITY ACTIVITIES

2.1 INTRODUCTION

2.1.1 To determine the revenue to be recovered from utility ratepayers, the Board must assess the forecast contribution of the Company's ancillary programs and the reasonableness of the costs removed for non-utility activities. This chapter addresses these and other related matters.

Background

2.1.2 Consumers Gas' core business activities are in the distribution, transmission, and storage of gas. These activities are regulated by the Board. Consumers Gas also provides a number of ancillary services which are viewed as complementary, but not essential, to the core business. The existing ancillary activities or programs are:

- Rentals ("rental program")
- Merchandise Sales Program ("MSP")
- Heating Insurance Program ("HIP" or "insurance program")
- Natural Gas Vehicle ("NGV") Program
- Agency Billing and Collection Transportation Service ("ABC T-service")

2.1.3 These ancillary activities, with the explanation noted below regarding the NGV program, are not regulated; the Company sets the prices for these services. The Board includes the revenues and costs of these activities in the determination of the

Company's revenue requirement for a test year. The Board's review focuses on issues of cross subsidy of ancillary operations by the core business. Prior to E.B.R.O. 495, costs were allocated to ancillary programs on a marginal cost basis; in that Decision, the Board determined that full costing should be applied thenceforth.

2.1.4 The NGV program involves the delivery and sale of gas to outlets for resale to the public; the program also involves the Company's investment in equipment and certain other activities aimed at promoting the program. Pursuant to the *Ontario Energy Board Act*, the Board approves or sets the rate for the gas delivered and sold by the Company to NGV outlets. The Board does not set any rates or charges associated with the Company's other activities in the NGV program, activities which may be viewed as the ancillary part of the program.

2.1.5 As part of the utility operations, the Company engages in certain other activities, such as furnace maintenance tune-up, home gas appliance inspection, and appliance repair and maintenance services. These activities, for which the Board does not approve prices, have not been given the status of ancillary programs, i.e., revenues and costs are not recorded separately for regulatory purposes.

2.1.6 The Company also engages in what are referred to as non-utility activities. These relate to the employment of the Company's competencies and resources outside the utility operations. Non-utility activities also involve the provision of goods or services <u>to</u> the Company's subsidiaries and affiliate companies, or the receipt of goods or services by the regulated utility <u>from</u> the Company's affiliates. These transactions are referred to as affiliate transactions.

2.1.7 In approving or setting rates for the Company's ratepayers, the regulatory review includes an assessment of the reasonableness of the Company's costing or pricing arrangements for such non-utility activities. Investments, costs and revenues are eliminated from the utility cost of service because they relate to non-utility activities. This process is referred to as a non-utility elimination. In most instances the cost amounts, and in all cases the revenue amounts, can be segregated from the Company's utility accounts.

2.1.8 However, the costs associated with the Company's corporate departments' involvement in non-utility activities are included in the utility's Administrative and General ("A&G") Overhead ("O/H") component of Operating and Maintenance ("O&M") expenses. Such costs are allocated to non-utility activities through a cost allocation procedure. Historically, this allocation is done on a fully allocated cost ("FAC") basis.

2.1.9 Prior to E.B.R.O. 495 the Company's Merchandise Finance Program ("MFP") was treated as an ancillary activity, in that costs eliminated were calculated on a marginal cost basis. However, unlike those of other ancillary programs, the revenues from MFP were not incorporated in the overall determination of the Company's revenue requirement for regulatory purposes.

The E.B.R.O. 495 Decision

2.1.10 In its E.B.R.O. 495 Decision, the Board ruled that the FAC methodology was to be applied thenceforth to all ancillary and non-utility programs and activities.

2.1.11 In that Decision the Board concluded that no general or special considerations justified exclusion from full costing for any of the Company's existing or proposed ancillary activities. However, the Board stated that possible exemptions from full costing may be warranted in special circumstances and that the Board would make this assessment as such circumstances arose.

2.1.12 For the 1998 fiscal year, the Board imputed revenue based on 25% marginal and 75% FAC to bring the combined rate of return of the ancillary programs to the same level as the overall allowed utility rate of return. This relief from the full revenue imputation essentially allowed for a three month transition period to the FAC methodology.

2.1.13 The Board also noted that the move to FAC would necessitate the production of a costing manual. The Board directed the Company to prepare and submit such a manual for its next main rates case. The Board deals with this matter later in this chapter.

2.1.14 With respect to the NGV program, the Board had concluded that, in the Company's next main rates filing, the Company must, for purposes of cost allocation and rate design, redefine the NGV program to distinguish that part of the program that requires rates to be set by the Board from the rest of the NGV ancillary program activities. This matter was settled in the Settlement Proposal, other than the issue of a Company proposal for an NGV Pilot program to be treated as part of the Company's Demand Side Management ("DSM") activities. This residual issue is dealt with below.

2.2 INCLUSION OF NGV PILOT PROJECT IN DSM

2.2.1 For a number of years, the Company has operated a Natural Gas Vehicles program in the Ontario market, a program that has been analyzed from a DSM perspective, but has been operated separately from the DSM Plan. For fiscal 1999, the Company proposed to conduct a small component of the NGV program as a DSM pilot project, and requested approval of a $300,000 expense to subsidize the incremental costs of providing a natural gas fueled option on cargo vans for use by high-mileage users, such as courier companies and delivery agents. The Company argued that the proposal will result in long term positive economic and environmental benefits to both ratepayers and society as a whole. The proposal was opposed by a number of intervenors, who argued that it was essentially a load building initiative, not properly part of a DSM program, and had no need of an incentive for the Company to pursue it.

2.2.2 The Board is not convinced that the proposed pilot project belongs within the DSM plan. Although there will be environmental benefits from the substitution of natural gas for other less desirable fuels, these benefits exist for all gas marketing initiatives. While the Board did note in its E.B.R.O. 495 Decision "suggestions concerning the possible affinity of the NGV program with the Company's DSM Plan", NGV programs have been viewed by the Board in the past as outside the ambit of DSM, and there is no evidence that this pilot project differs in any way from those programs. Since the Company stated that the proposal would not proceed unless the costs were approved as part of the O&M budget and the program was not subjected to revenue imputation, the Board has assumed that the pilot program will not proceed in the test year. The $300,000 proposed expense is not included in the Board-approved 1999 O&M expense budget.

2.3 ABC T-SERVICE

2.3.1 ABC T-service can generally be described as an optional billing and collection service for an Agent, Broker or Marketer ("ABM"). It is the primary vehicle for residential marketing by ABMs. The Company first introduced ABC T-service as a concept in E.B.R.O. 492 which dealt with the Company's 1997 fiscal year. In that proceeding the Company requested that the service, which was yet to be launched, be classified as core-utility. The Board found that it would view the service as an ancillary program during the interim to facilitate its introduction. In the subsequent main rates case, E.B.R.O. 495, the Company requested the continuation of the program as ancillary and the Board found that the service should be classified as such. Consequently full costing was also to apply to this service.

2.3.2 In the present proceeding the Company requested that ABC T-service be classified as part of the core-utility. The Company therefore used marginal costing to calculate the rate of return on the program. An additional revenue of $600,000 would be required under FAC to bring the program's rate of return up to the 9.04% utility overall rate of return reflected in the Company's filing.

2.3.3 The Company's reasons in support of its request to classify the service as core-utility reflected the general theme that the 15 cent increase in the monthly fee, to 80 cents, that would be necessary under full costing, would spell the demise of the Company's ABC T-service, as the service would be forced to compete with those provided by other market players. However, the Company also conceded that the financial consequences of not meeting forecast revenues was part of the reason for the Company's request.

2.3.4 Of the eight parties addressing this issue in their arguments, only Energy Probe fully supported the Company's proposal. CEED's support was conditional on a Board directive that the Company unbundle its billing and collection service in the next main rates case so that monopoly billing is not the only option for a single bill arrangement.

2.3.5 The Board accepts that ABC T-service is an important service in that it is presently utilized by ABMs active in the small customer sector. However, the benefit to the market of ABC T-service is a rationale for its existence, not a criterion for its classification. In that regard, the Board does not accept the Company's and Energy Probe's arguments for core-utility classification. The Board does not consider meritorious the argument that the number of customers anticipated to avail themselves of this service in the test year (approximately 400,000) is determinative of a service's classification. As certain intervenors noted, the water heater rental program has a very high percentage of the total customer base, yet it has always been classified as ancillary. ABC T-service is not a monopolistic service; it is clearly secondary to the Company's prime business.

2.3.6 The Board notes from the parties' arguments that there are different perceptions as to whether there are currently alternatives to the Company's ABC T-service. In the Board's view, the answer is not critical. To the extent that there are no viable alternatives at this time, this should alleviate the Company's concerns that competition would prevent it from meeting its revenue forecasts for the test year. On the other hand, marginal costing that would be associated with the classification as core-utility could, as noted by certain intervenors, result in a subsidy and needlessly impact any current or future potential competitor for that service, be it an ABM undertaking its own billing, or a third party seeking to offer such service as a business. In that regard the Board rejects the Company's argument that classification of ABC T-service as a marginally costed core-utility service would not preclude ABMs from developing their own billing capabilities.

2.3.7 The Schools suggested that a variance account be created to capture any revenue shortfall. The Board notes that while the Company had not requested such an account, the Company saw merit in the School's suggestion. After careful consideration, the Board has rejected this suggestion on the grounds that it would be atypical for the Board to authorize a deferral or variance account for a service that is ancillary and for which the fee is not approved by the Board.

2.3.8 CENGAS' support for ancillary status of the ABC T-service and full costing is connected with CENGAS' desire to offer its own billing service; CENGAS' members do not have confidence that the Company's CIS will be capable of meeting ABMs' future needs and, in any case, CIS will be transferred to an affiliate which will compete directly with CENGAS members. To facilitate an ABM's ability to provide its own billing service, CENGAS requested that the Company be ordered to provide common account numbers and a seamless electronic transfer of consumption data from the Company to any ABM sponsored billing service. The Company did not specifically address CENGAS' request. In the Board's view, these matters should be dealt with in other forums available to the industry, including the Ontario Energy Marketers Association ("OEMA") and possibly the Market Design Task Force. In the absence of any evidence that this matter cannot, or should not, be dealt with in these other forums, the Board is not prepared to consider this issue further at this time.

2.3.9 The Board concludes that there are no new material facts presented in this case that should lead to a reversal of the Board's findings in E.B.R.O. 495. The Board finds that the ABC T-service should continue to be classified as ancillary and full costing should apply to the program for ratemaking purposes. The Board notes that, given the lower overall rate of return found in this Decision compared to the rate of return filed by the Company, the required 15 cent increase calculated by the Company will be lower.

2.4 RATE OF RETURN OF ANCILLARY PROGRAMS

2.4.1 The Company's Rentals ("the rental program"), Heating Insurance Plan ("HIP" or "the insurance program"), Merchandise Sales Program ("MSP"), and Natural Gas Vehicle ("NGV") Program ("the four ancillary programs") are forecast to produce a rate of return on a combined basis of 7.11% for the test year. Compared to the overall 9.04% utility rate of return included in the Company's filing, the programs will, according to the Company, produce a revenue deficiency of $21.3 million in 1999. The Company requests that the Board not impute any revenue to these programs.

2.4.2 The Company's position in testimony and in argument is that the Board's direction to adopt full costing in E.B.R.O. 495 introduced a "shock" and a "turnaround" situation, and that "special circumstances", "past benefits", "competition" and "regulatory balance and fairness" mandate exemption from full costing for the test year and probably longer. In effect the Company requests that the Board refrain from applying full costing to these programs for the test year.

2.4.3 The identification of the source of the claimed revenue deficiency occupied considerable hearing time. Eventually, it became evident that the main reason for the apparently large forecast 1999 revenue deficiency in the four ancillary programs is related to the Company's "diagnostic activity" which the Board understands as diagnosing the source of a problem which has prompted a customer service call. The Company's prefiled evidence concerning the accounting treatment of costs and revenues related to diagnostic services was of little assistance. Below are the Board's understandings, conclusions and findings.

2.4.4 Because of certain links between the forecast rate of return for ancillary programs and the O&M schedule that became evident in discussing diagnostic service costs and revenues, it is helpful to begin by setting out these links. The Company's O&M schedule includes:

- An amount for Jobbing Contract Margin which is the <u>net</u> of Jobbing Contract Revenue (generated from the billing of certain services) and Jobbing Contract Expenses (the direct costs associated with the provision of the services). For 1999 the margin is forecast to be positive.
- An amount for Customer Generated Service Work which is the <u>net</u> of Customer Generated Service Work Revenue and Customer Generated Service Work Expenses. For 1999 the net amount is forecast to be negative since there are few activities for which there are charges to customers.
- Amounts for Ancillary Program Expenses. These are the <u>direct</u> expenses associated with ancillary programs; the indirect expenses are included in other O&M expense items and are allocated to ancillary programs through the Company's cost allocation procedures.

2.4.5 Prior to February 1998 all ratepayers received "free" diagnostic services, that is there was no specific charge for the first half hour of diagnostic service. The costs incurred by the utility for diagnostic work were embedded in utility O&M expenses and recovered through delivery rates. Apparently, the Company's FAC presentation in E.B.R.O. 495 did not identify and therefore did not allocate to the ancillary programs any of the costs associated with diagnostic activities.

2.4.6 In February 1998 the Company introduced a diagnostic service charge. However, customers under the rental or insurance programs did not pay a separate charge. For those customers the Company decided that the fees paid for those programs would include the costs of diagnostic services. With the introduction of diagnostic service charges, certain changes were made by the Company to its presentation of the O&M schedule, impacting both the amounts shown in that schedule and the indicated profitability of the ancillary programs.

2.4.7 Previously, the costs incurred for diagnostic services were included as costs for Customer Generated Service Work. Along with the introduction of the diagnostic service charge the Company reclassified diagnostic service costs. The direct costs related to the rentals program were transferred to Ancillary Program Expenses, which capture the <u>direct</u> costs for ancillary programs. The remaining diagnostic service costs were classified as Jobbing Contract Expenses, which would appear not to be directly allocated to a specific activity but to be allocated on the basis of the Company's cost allocation procedures.

2.4.8 These changes resulted, for 1999, in an $8.1 million reduction to costs of Customer Generated Service Work, partially offset by increases of $3.1 million in Ancillary Program Expenses and $3.5 million in Jobbing Contract Expenses. The $1.5 million difference between $8.1 million reduction and the combined $6.6 million increase is a reflection of the Company's expectation of reduced demand for diagnostic services because of the introduction of the charge. The reclassification of diagnostic service costs already included in the overall O&M schedule does not in itself affect the bottom line of that schedule.

2.4.9 However, the introduction of diagnostic service charges and the Company's decision to reclassify diagnostic service costs resulted in an additional $13.3 million for Jobbing Contract Revenue for 1999 (for 1998 the amount was estimated at $7.5 million). Of the $13.3 million amount, $5.6 million is associated with third party revenue (revenue generated from customers outside the rental and insurance programs); the $7.7 million balance represents a "charge" to the insurance program, as if that program were collecting diagnostic service charges from its customers. No such "charge" was imposed on the rental program.

2.4.10 Turning to the financial implications of the changes for the four ancillary programs, as noted earlier the change in the cost accounting results in additional $3.1 million direct costs for the rental program. Also, the identification of diagnostic service costs resulted in an additional $6.8 million of allocable costs assigned to the rental program. With respect to the insurance program, there was no evidence to ascertain the portion, if any, of the $3.5 million in diagnostic service costs transferred to Jobbing Contract Expenses that was attributed to that program. However, associated with the increase in Jobbing Contract Revenue of $7.7 million for the insurance program, there was a corresponding "debit" or "charge" to Other Revenue in the Utility Income statement, a revenue account external to the O&M schedule.

2.4.11 The net impact of the above on the four ancillary programs is to depress their forecast profitability. Through an undertaking, the Company's restatement of the 1999 revenue deficiency by "excluding the costs associated with the diagnostic service" reduced the forecast revenue deficiency of the four ancillary programs by $17.6 million, from $21.3 million to $3.7 million. The reduction is comprised of $3.1 million and $6.8 million in direct and allocable costs respectively associated with the rental program and the $7.7 million "charge" to the insurance program, presented as a reduction in Other Operating Revenue on the Utility Income Statement.

2.4.12 All intervenors who made submissions on this matter urged the Board to impute revenue of $21.3 million for the four ancillary programs and to find that the Company's presentation in its original filing was an attempt to mask, and did mask, the fact that the true O&M expenses budget for 1999 and the 1998 O&M expenses estimate for 1998 are both higher than the Company alleged. The intervenors noted that the "masking" of the true budget was particularly critical at this time given the Company's expectation that the 1999 O&M expenses budget will serve as the base for incentive ratemaking, the subject matter of the second phase of this proceeding.

2.4.13 Whether or not there was an attempt to "mask" the true O&M expenses, the Board shares the view that the accounting treatment and presentation of diagnostic service costs and revenues distorted the true picture. The Board deals with these issues in relation to an appropriate O&M expenses budget for the test year later in the Decision.

2.4.14 The Board has noted intervenors' arguments to the effect that, by charging for diagnostic services, the Company's problems with the forecast 1999 revenue deficiency of the ancillary programs are "self-induced". In the Board's view, the Company should not be criticized for identifying omissions, making refinements to its cost allocation, or espousing a user-pay principle. The issue is a different one. It is clear from the evidence that the Company did not allocate the costs associated with diagnostic services when it presented the results of the FAC study in E.B.R.O. 495. Implicit in the Company's present position is that, had the outcome of full costing been properly anticipated in E.B.R.O. 495, the Board may not have opted for full costing or may have provided for a longer transition period.

2.4.15 It is clear in the E.B.R.O. 495 Decision that the Board <u>first</u> considered the principle of an appropriate cost allocation and <u>then</u> considered resulting impacts on the Company. Had the Company identified the higher cost impacts, there is nothing to suggest that the Board might have allowed for a longer transition period. In any event, the effect of the new facts is that the Company has had a transition period for the true revenue deficiency of the ancillary programs for fiscal 1998. This negates the Company's arguments for allowance of a longer transition period. The Board finds that full costing shall continue to apply to the four ancillary programs.

2.4.16 The Board is concerned as to what other costs properly belonging to either ancillary or non-utility activities are still missing in the Company's cost allocation. Certainly, the omission of costs related to diagnostic services calls into question the reasonableness of the Company's previous procedures in allocating costs to the ancillary programs or to non-utility activities. It certainly diminishes the Company's arguments regarding past benefits to ratepayers from the ancillary programs when it appears that, even on the historic marginal costing basis, some direct (marginal) costs attributable to ancillary programs have been excluded in calculating their profitability.

2.4.17 The Board observes that $9.9 million of the $17.6 million change in revenue deficiency for the ancillary programs relates to the identification of diagnostic service costs related to the rental program. Had the same treatment been applied to the insurance program as to the rental program, the remaining $7.7 million revenue deficiency for the insurance program would not have arisen. Whatever the accounting treatment appropriate to costs and revenues relating to a specific program may be, for regulatory purposes, the Board requires complete disclosure of the impacts, and consistency in presentation among programs.

2.4.18 With respect to an appropriate imputation of revenue for the four ancillary programs, the Board concludes that, for purposes of estimating the rate of return for the ancillary programs, the $7.7 million charge to Other Revenue should be reversed. As a result the revenue for the insurance program would increase, and the revenue deficiency for the four ancillary programs would decrease by $7.7 million, from $21.3 million to $13.6 million. The reversal results in a corresponding decrease in the Jobbing Contract Revenue in the O&M schedule, as discussed in Chapter 3.

2.4.19 As noted earlier in this chapter, the Board rejects the Company's request to change the classification of the ABC T-service program from ancillary to core-utility which would have resulted in avoiding full costing. This finding leads to an additional revenue imputation of $0.6 million based on an overall rate of return of 9.04%. Also, the Board rejects the Company's request discussed elsewhere in this Decision to implement certain changes to the capitalization of A&G overhead costs, which finding results, according to the evidence, in an additional revenue imputation of $0.4 million to the ancillary programs based on an overall rate of return of 9.04%.

2.4.20 Further, the Board notes the Company's evidence that while some of the costs associated with the preparation of the cost allocation study are attributed to non-utility activities, no costs are attributed to the ancillary programs. While the Board sees no reason from an overall utility revenue requirement to make an adjustment at this time, the Board is not persuaded by the Company' arguments that these costs are incurred as part of the regulatory process. The cost allocation activity is caused as much by ancillary program as by non-utility activities.

2.4.21 The total revenue imputation for the Company's ancillary programs must, however, reflect the fact that the lower level of 1999 O&M expenses found appropriate by the Board in Chapter 3 will impact the costs allocated to the ancillary programs. Lower O&M expenses attributable to these programs result in a higher forecast rate of return for the programs. The evidence available does not provide for a precise calculation of such impact. Based on the information available regarding the relative responsibility of the ancillary programs for O&M expenses, the Board deems that some $3 million of the Board reduction to 1999 O&M expenses is related to the Company's ancillary programs.

2.4.22 The total revenue imputation for the Company's ancillary programs for the 1999 test year is therefore estimated at $11.6 million on the basis of the 9.04% utility rate of return reflected in the Company's filing, which incorporates a rate of return on common equity of 10.30%. According to the evidence, a decrease of 25 basis points in the allowed rate of return on common equity produces a reduction of the revenue deficiency for the ancillary programs of approximately $1 million. In view of the 9.51% rate of return on common equity found by the Board in this Decision, the Board extrapolates the calculated decrease to $3.2 million and imputes a resulting revenue of $7.7 million to the Company's ancillary programs for the test year. The Board's findings and adjustments are summarized in the chart below.

1999 REVENUE IMPUTATION TO ANCILLARY PROGRAMS	
	($ Million)
Claimed revenue deficiency	21.3
Restatement of HIP revenues	-7.7
Restated revenue deficiency	13.6
Adjustment for ABC T-service	0.6
Adjustment for A&G O/H	0.4
Adjustment for O&M expense reduction	-3.0
Revenue deficiency at 9.04% ROR	11.6
Adjustment for lower ROR (8.67%)	-3.2
Revenue deficiency per Board	8.4

The $8.4 million revenue imputation is added to the $7.7 million restatement resulting in an upward adjustment to Other Operating Revenue of $16.1 million, as shown in Appendix B.

2.4.23 One matter relating to ancillary programs remains to be addressed. It is not clear from the evidence on the record in this proceeding how the Company assures that customer service calls relating to safety are not discouraged by the imposition of a separate charge for diagnostic services; the Board would be concerned if the Company's responsibility for customer safety were to be reduced in any way by the introduction of these charges. The Board directs the Company, in light of the diagnostic service charge, the Company's unbundling plans and the planned transfer of service work to Consumersfirst, to clarify the situation in Phase II and satisfy the Board that customer safety is not compromised by the changes that have already taken place or will occur as a result of unbundling.

2.5 NON-UTILITY ELIMINATIONS

2.5.1 Since the costs associated with the non-utility functions performed by the departments, regions and executives of the Company are included in Administrative and General expense accounts in the O&M schedule, such costs are identified through a cost allocation procedure and are then eliminated. The Company requested that the Board approve a gross non-utility elimination of $15.0 million for the 1999 test year. This amount is comprised of $8.6 million in allocated costs (derived from the activity analyses) plus $6.4 million of other items. The $6.4 million amount includes $2.1 million for unspecified activities during fiscal 1999. Since the Company's 1999 O&M budget already includes a reduction of $4.2 million for recoveries from direct billings and management fees (to its affiliates), the non-utility elimination in the Company's Administrative and General expense accounts is $10.8 million ($15 million less $4.2 million).

2.5.2 A number of intervenors expressed concern regarding the processes and procedures used to determine the non-utility eliminations and recommended that the Board direct an external audit. These matters have been addressed by the Board elsewhere in this Decision under the heading Cost Allocation Process and Manual.

2.5.3 The Company's record in accurately forecasting non-utility eliminations also occupied substantial time at the hearing. As CAC noted, the variances between forecast and actual non-utility eliminations in the past two fiscal years are a further demonstration of the Board's conclusions in E.B.R.O. 495 of a consistent pattern of understatement of non-utility eliminations on a forecast basis. The fact that an allowance has been instituted for unspecified activities in recent years is further testimony of the difficulties in forecasting non-utility activities and costs. The allowances for the unspecified activities over the last two years have failed to capture the full impact of those activities. These facts and observations lead the Board to conclude that as non-utility activities are on the increase, as the evidence attests, the past behavior and direction of variances will likely continue. Certainly there is no evidence of such trend reversing itself.

2.5.4 The Company acknowledged that it has historically experienced substantial variances in the non-utility elimination, but the Company asked the Board to distinguish the sources of the variances and to consider the action taken by the Company as adequate.

2.5.5 The Company distinguished three categories for variances from forecasts: new items which were not in the original forecast, uncontrollable events (such as regulatory policy changes), and increased levels of non-utility activity. It was the Company's position that the variance attributed to changes in the level of activity and related costs is the only component of the variance indicative of forecasting accuracy. The Board does not accept the Company's position that it is only in this category that the Company's proposals should be assessed. From a ratemaking perspective, whatever the cause or causes of a forecast underestimation in a given year it results in higher rates than otherwise would be the case. The pattern of underestimation discussed in last year's hearing is still evident in this proceeding.

2.5.6 The Company contends that as a regulated utility, it is one of management's duties to ensure that there is no cross-subsidization between the Ontario utility and non-utility operations. The Board agrees. However, if the context of that contention is, as it appears to the Board to be, that the Company's forecasts should not be questioned, the Board finds such a suggestion inappropriate.

2.5.7 The Schools suggested that the Board should discourage the provision of services to affiliates, with the exception of regulated affiliates. As much as this scenario would simplify the regulatory process, there are other considerations and implications of such an action which have not been explored in this hearing.

2.5.8 On the basis of concerns of under-allocation of costs to non-utility activities due to the cost allocation procedures discussed elsewhere in this chapter and of further confirmation of past trends in underforecasting non-utility eliminations, the Board concludes that a reasonable forecast for non-utility eliminations for the 1999 test year is an amount of $12.0 million, an increase of $1.2 million over the amount, $10.8 million, proposed by the Company.

2.5.9 As described in the Settlement Proposal, the parties had agreed that the Company refile its application to the Board for a deferral account dealing with the incremental costs associated with the Company's unbundling activities where, as originally anticipated, unbundling matters (E.B.O. 179-15) would be also examined. With the deferral of E.B.O. 179-15 to Phase II, it was the Company's proposal that the treatment of such incremental costs should wait for that time. Certain intervenors argued that non-incremental costs associated with unbundling, estimated by some at about $2.0 million, ought to be eliminated now from the Company's O&M schedule. In the Board's view, whether or not additional non-utility eliminations ought to be assessed is an issue appropriately to be considered in conjunction with the incremental costs in Phase II of the proceeding.

2.6 COST ALLOCATION PROCESS AND MANUAL

2.6.1 The Cost Allocation Manual prepared in response to the Board's direction in E.B.R.O. 495 was filed by the Company. The Manual was not used in the Company's cost allocation process for this test year, but was a codification of the methodology that was utilized. To obtain the fully allocated costs necessary for regulatory purposes, the Company must directly allocate those costs to the ancillary and non-utility programs which are clearly marginal to those programs, and would not be incurred if those programs ceased to exist. To those marginal costs an appropriate allocation of non-segregated costs which are incurred for both utility and other activities, such as the O&M costs associated with functions performed by departments, regions and executives, and other costs related to shared services between the utility and the other programs, must then be added.

2.6.2 The process involves managers in 107 departments annually allocating the total costs to be allocated to each of 38 ancillary, non-utility and utility cost centres based on activity analysis worksheets. The methodology comprises a bottom up activity analysis using one or more activity-specific cost drivers selected from a common set of cost drivers, including time allocations, head count, transaction numbers, composites of executives and rate base. The activity analysis work sheets allow managers to estimate and record the volume (amount) of each cost driver which is associated with their department's activity for each of the 38 cost centres. The results are submitted to the cost accounting group who input the driver volumes resulting from the worksheets into the cost allocation model which then allocates O&M and capitalizable A&G overheads to the utility, non-utility and ancillary businesses based on the total driver volumes.

2.6.3 As a result of the Company's allocation process, the 1999 O&M expense allocation to ancillary programs was increased by about $29.5 million to $35 million compared to a marginal cost allocation of about $6.5 million, and the non-utility elimination related to the MFP was more than it would have been under marginal costing.

2.6.4 The Company submitted that it had fully complied with the Board's directive in the E.B.R.O. 495 Decision in that it has procedures and controls in place to ensure the completeness and accuracy of the results of the cost study and that an external audit is neither required nor warranted.

2.6.5 The Board has three fundamental concerns about the methodology as applied to 1999 and reflected in the Manual:

- the pre-classification of certain costs as utility only by senior management;
- the appropriateness of certain selected cost drivers on cost causality grounds: and
- the time and effort involved compared to the results of the study.

2.6.6 In respect to the first concern, it is evident to the Board that in some cases Senior Management has issued top down instructions to classify certain costs, for example unbundling costs, as utility only, regardless of what a proper activity analysis would reveal. In the example of unbundling costs, the Board does not accept the matching of costs and benefits rationale advanced by the Company since it is still to be determined who will benefit from unbundling. The Board also finds that there is an apparent continuation of historic classifications by some managers without a supporting activity analysis. For example, all Technology and Development ("T&D") costs are pre-classified as utility except for those associated with IPLE's research and development program, despite the fact that a matching of costs and benefits under fully allocated costing would appear to require that some of the department time spent managing water heater and furnace related projects should be allocated to ancillary programs. The Company indicated that if the ancillary programs did not exist, the research and development work on utilization equipment would continue since it enhances the use of natural gas. The Board finds this position reflects the historic marginal cost approach and not the required fully allocated cost approach. For FAC purposes, T&D department activity should be allocated based on the characteristics of the assets being developed, as, for example, metering (distribution) versus water heaters (ancillary). This finding if implemented, would result in an increase in allocation to the ancillary programs.

2.6.7 With respect to the appropriateness of cost drivers, the Board notes that approximately $9 million of the residual costs after allocation of regulatory and directly attributable governance-related costs (Corporate Sustaining Cost Pools #2, 3 and 4) were distributed based on either headcount or rate base/capitalization drivers. Since utility capitalization and headcount are approximately 83% of the total of utility, affiliate and ancillary driver volumes, this automatically attributes 83% of these costs to the utility. However the Company failed to demonstrate that the underlying activities are not driven significantly by the non-utility and ancillary activities. The Board finds that a better cost driver is needed to allocate the Corporate Sustaining Cost Pool costs more appropriately to the utility, non-utility and ancillary activities. This finding if implemented would increase the allocation to non-utility and ancillary programs.

2.6.8 Finally, the Board finds that although the cost allocation is only performed once a year, the complexity of the process, the likely time and costs involved and the inherent level of accuracy, do not warrant the result. The Company should address ways in which the process can be simplified and improved. The Board suggests that the whole exercise be conducted by the accounting department and be based on applying appropriate cost drivers to the allocable costs at a more aggregate level.

2.6.9 In addition the Company should assess the merits of having the accounting group directly input the cost driver volumes to the model after having completed a prior year variance analysis based on contacting operational departments and taking into account year over year budget changes.

2.6.10 Overall the Board finds that the process of cost allocation followed by the Company tended to understate the costs to be allocated to the non-utility and ancillary programs. Elsewhere in this Decision the Board has made findings concerning the appropriate level of the non-utility elimination and has imputed revenues for the ancillary programs to bring their rates of return to appropriate levels, findings consistent with, and based in part on, the Board's concerns about the cost allocation process.

2.6.11 In addition, the Board directs the Company to review the general methodology of the activity analyses and the specific problem areas identified in the Board's findings and to modify the approach and input assumptions for the next test year. The Board does not believe that an independent audit would be useful at this point.

2.6.12 The Board's findings on using the activity analyses in the Manual for capitalization of A&G overheads are set out in Chapter 3.

3 COST OF SERVICE ISSUES

3.0.1 This chapter deals with a number of cost of service issues requiring Board findings. The main topic areas are:

- O&M Expenses
- DSM Plan
- Capital Budgets
- Cost of Capital

3.1 O&M EXPENSES - 1998

3.1.1 In E.B.R.O. 495, the Company had proposed a 1998 budget of $260.4 million, but the Board made a general reduction of $7.7 million, and specific reductions of $2.7 million for a final Board-approved figure of $250.0 million. The Company was in the early stages of preparing its fiscal 1999 budget when it received the Board's decision with respect to the 1998 fiscal year; the Company outlined the steps it took in response to the Board's decision, and the subsequent process of developing its 1999 proposed budget.

3.1.2 It was the Company's evidence that it was forced to rethink business plans and initiatives to meet the reduced expenditures levels imposed by the Board for 1998. To accommodate the reductions the Company stated that, among other things, it:

- constrained Call Centre costs;
- reduced Information Services spending, especially relating to strategic planning;

- reduced sales and marketing expenses, through elimination of several marketing initiatives, which could, in the long run, reduce future customer attachments;
- reduced research and industry monitoring; and
- reduced employee training and professional development.

3.1.3 During the hearing, the process followed by the Company in responding to the Board's decision with respect to the 1998 O&M budget was examined in detail. Included in the evidence examined was a memorandum from the then President of the Company, Mr. R.D. Munkley, produced in response to an undertaking request. This memorandum, directed to senior personnel responsible for managing 1998 O&M expenditures and for developing the 1999 budget, outlined specific targets for both the 1998 and 1999 O&M expenditures. For 1998, a "target" of $244.1 million "overall O&M costs" was set. Company witnesses explained that this target reflected a final O&M budget of $250 million "taking into consideration the direct ancillary program costs and the Non-Utility adjustment." In directing attainment of this budget level, the memorandum stated that "Business units impacted by customer growth must focus on decreasing total O&M cost per customer. Other business units will need to realize a net decrease in their total O&M expenses". The memorandum also emphasized the importance of generating new revenues.

3.1.4 Company witnesses expanded on the Company's responses to the Board's decision, noting that both cost reduction and revenue generation measures were developed. Remote cashier operations were discontinued, meter exchanges were curtailed, staff replacement and student hiring were reduced, additional safety initiatives were postponed, and meter reading frequency was reduced. To generate revenues, project management fees and customer meeting charges for large volume customers were introduced, and as discussed in Chapter 2, a charge for diagnostic services was implemented in February 1998.

3.1.5 The Company presented its 1998 O&M estimate in this proceeding as $249.6 million (inclusive of ancillary expenses and exclusive of non-utility expenses), a figure within the Board-approved budget of $250 million. The estimate also included revenues which were not forecast in the $250 million budget, notably revenues from the newly implemented diagnostic service charges, embedded in the O&M presentation. The Board has found it to be a difficult and time-consuming exercise to disentangle the presented information in order to assess the 1998 estimate (and the test year budget) on a basis that is comparable to the figures approved by the Board in the last rates case. The task has been complicated by the links between the treatment of revenues and costs for ancillary programs to the presentation of the O&M expenses, as noted in Chapter 2.

3.1.6 In determining the O&M budget for 1998, the Board used an envelope approach, "leaving the remaining allocation of the *reduction in spending* to the Company's discretion" [E.B.R.O. 495, p110, emphasis added]. The Board was not aware, when it approved an overall 1998 O&M budget of $250 million, of the possibility of additional revenues being used to offset O&M expenditures to attain the budgeted total. It appears that the "real" revenues from diagnostic charges for 1998 are approximately $4.3 million, and that there are some additional revenues from other newly implemented charges.

3.1.7 In both its prefiled evidence and through witnesses at the hearing, the Company has made much of the lengths to which it had to go to implement the reductions in O&M spending mandated by the Board for the 1998 fiscal year. However, on a restated basis comparable to the presentation in E.B.R.O. 495, the 1998 estimated O&M expenditures are, according to the Company, $257.8 million, only $2.6 million less than the Company's original proposed 1998 budget. The Board finds it difficult to understand why the Company would need to take drastic measures to accommodate such a small spending reduction. Once the Company had determined that much of the O&M reduction imposed by the Board could be made up through a charge for diagnostic services and other unregulated revenues, few O&M cost reductions would appear to be necessary, at least within the regulated utility.

3.1.8 In addition, the Board notes that the approved 1998 O&M budget included a management fee payment to IPLE of $500,000. The Company estimates that the total 1998 fee will be $2.2 million. Had the Company paid only the approved fee, an additional $1.7 million would have been available for other O&M expenditures, such as the maintenance of the level of service offered through the Call Centre.

3.1.9 While the Board is not required to make a specific finding relating to the 1998 budget estimate, it is important that the Company ensure that its O&M presentation is such that the Board is able to clearly identify the proposed increases in O&M spending year over year. The Board comments on the Company's presentation later in this chapter.

3.2 O&M EXPENSES - 1999

3.2.1 The Company's proposed 1999 O&M budget is $280.0 million as shown in the table below. This proposed figure includes forecasted revenues and avoided costs totaling $14.8 million resulting from the institution of charges for diagnostic services. When these revenues and avoided costs are taken into account the 1999 O&M figure comparable to the 1998 estimate of approximately $258 million, noted above, is approximately $295 million, an increase of approximately 14%.

3.2.2 Evidence filed by the Company in response to an undertaking request during the hearing indicated several different categories of expenditures which make up the proposed increase in O&M expenditures:

- a 2.9% increase or $7.2 million over the $250 million Board approved 1998 budget for expenditures relating to customer growth, inflation, and increased compensation costs, after taking into account possible productivity initiatives and savings of $3.4 million;
- specific costs of $2.9 million proposed as necessary to reinstate service levels and operating initiatives which had been cut in responding to the Board's decision to reduce the 1998 budget;
- $3.6 million relating to "improved customers service levels and unrealized CIS benefits"; and
- additional "one time incremental costs" associated with Year 2000 ("Y2K") of $11.7 million, and a further $4.6 million for upgrading the Legacy systems.

The resulting $280 million includes costs of $8.2 million which are a result of the delay in implementation of CIS, $1.5 million of which relate to Y2K preparations.

PROPOSED OPERATIONS AND MAINTENANCE EXPENSE BY COST ELEMENT			
Item No.	**Account**	**Budget 1999 ($ millions)**	**Estimate 1998 ($ millions)**
1.	**Gas Supply & Storage Operations**	**9.0**	**8.7**
2.	**Distribution**		
2.1	Distribution Operating	13.0	12.1
2.2	Regulated Service Work	3.6	2.7
2.3	Engineering and other Operations	3.4	3.2
2.4	Distribution Maintenance	10.5	10.1
2.5	Measurement & Regulation	6.8	6.4
2.6	Jobbing Contract Margin	-14.4	-9.9
2.7	Customer Generated Service Work	23.3	23.2
2.8	NGV Business Development	1.9	1.9
2.9	Technology & Development	3.9	3.6
	Total Distribution	**52.0**	**53.3**
3.	**Sales and Marketing including DSM**	**16.9**	**19.3**
4.	**Customer Support Services**	**53.5**	**46.7**
5.	**Administrative and General**		
5.1	Executive & Area Administration	6.7	6.7
5.2	Corporate Support Departments	38.4	37.3
5.3	Special Services	0.5	0.5
5.4	Claims, Damages and Insurance Premiums	5.3	4.0
5.5	Human Resources	51.9	46.9
5.6	Other Administration & General Expenses	4.8	5.1
5.7	Information Services	41.0	42.3
5.8	Overhead Charges to Construction	-21.3	-24.7
5.9	Billing & Customer Service Charge	0.0	0.0
5.10	Non-Utility Adjustment	-10.8	-9.1
5.11	Year 2000 Program	11.7	0.0
5.12	Legal Customer Systems	4.6	0.0
	Total Administrative & General	**132.8**	**109.0**
6.	**Total Utility O&M Expenses**	**264.2**	**237.0**
7.	**Ancillary Program Expense**	**15.8**	**12.6**
8.	**Total Operating & Maintenance Expenses**	**280.0**	**249.6**
Source: D3/Tab3/Sch2/Pg. 1 & 2, 98-4-3 update			

3.2.3 Specific areas of the Company's proposed spending contributing to the $7.2 million increase noted above are discussed below.

3.2.4 <u>Customer Growth:</u> About $4.9 million of the $7.2 million increase is directly attributed to customer growth. The Company argues that expansion of the customer base is beneficial to ratepayers, and that although it causes an upward pressure on operating costs, the costs per customer are declining.

3.2.5 <u>Compensation Costs:</u> About $4.1 million of the $7.2 million increase is attributed to Wages and Salaries. The proposed 1999 compensation budget includes $4.7 million for a proposed variable pay or "Success Sharing" program. When this incentive pay proposal is added to structural increases, supervisory salaries will increase by 3.74%.

3.2.6 <u>Reinstatement and Improvement of Service Levels</u>: The Company argued that it had to reduce service levels in its Call Centre and in the meter reading area in 1998 in response to Board budget reductions, and that these must now be "restored". The $3.6 million identified as necessary for these purposes includes $2.2 million in foregone CIS benefits. A further $2.9 million in additional O&M spending is proposed for the reinstatement of other "deferred" initiatives, including specific marketing initiatives, Information Services planning function, and specific initiatives in Distribution Operations including spending related to Technology and Development and staff replacements.

3.2.7 The Board has noted above that the proposed 1999 budget comparable to a 1998 base is approximately $295 million. However one calculates the "real" proposed 1999 O&M budget, the Board finds that the proposed increase in O&M expenditures is unreasonable. The Board has two choices: it could determine a "real" figure for the proposed 1999 expenditure, and then adjust it in accordance with the Board's findings, or it could begin with the 1998 estimate, and approve a reasonable increment over that budget, based on the Board's findings on the Company's evidence on the cost of forecast system expansion and the agreed upon inflationary figure, taking into account any one time expenditures that the Company has adequately supported. The Board has chosen the latter approach, an approach it finds to be consistent with the envelope approach taken in E.B.R.O 495.

3.2.8 Notwithstanding the difficulties in establishing a meaningful estimate of the 1998 O&M expenditures, the Board has determined that the 1999 O&M budget should be set by accepting a baseline 1998 amount, and approving those additions to the base that have, in its view, been justified by the Company. For the purposes of this calculation, the Board begins from the 1998 approved O&M budget of $250 million.

3.2.9 To the base amount the Board adds:

- An amount to reflect the costs related to customer additions for the test year. Evidence indicated a 3.9% increase in the number of customers over 1998. Customer related O&M expenditures are estimated by the Board to be approximately one-half of the O&M budget, or $125 million. Given the increase in customer numbers, an additional $4.9 million would be justified.
- An amount for inflation at the agreed upon rate of 1.9%.

3.2.10 From the resulting total of $259.7 million, the Board subtracts an amount to reflect productivity improvements. The Company presented a budget containing productivity savings of $3.4 million. It is not ascertainable from the evidence to what extent the Board's overall reduction in 1999 O&M expenses impacts the $3.4 million estimated amount. For purposes of setting rates in the test year the Board deems a $1 million reduction in the base amount for productivity savings.

3.2.11 The basic O&M expenditures budget for 1999 is therefore $258.7 million, before adjustments relating to the Board's findings on non-utility activities, and on issues raised in the proceeding concerning changes to the IPLE management fee, and requested one-time expenditures on Y2K and Legacy systems.

3.2.12 The Company's estimate of the appropriate non-utility elimination from the O&M schedule was $10.8 million. As noted above in Chapter 2, the Board has determined that this amount should be increased to $12.0 million. As a result of this determination, a $1.2 million reduction is made to the 1999 O&M budget.

3.2.13 As to the one-time expenditures that the Company proposed related to the upgrade of the Legacy systems, the Board must determine what portion of these expenses have been justified and should be the responsibility of the ratepayer. According to the Company, the Legacy systems upgrade is required because of the delay in implementation of CIS. During the hearing the Company was given a number of opportunities to explain the CIS delay, and provide evidence to justify the consequent expenditures, but it was unwilling to do so. In the Board's view, the onus is on the Company to satisfy the Board that ratepayers should bear these expenses, an onus it has not met at this time. The Board is therefore not prepared to add an amount to the approved O&M budget for this upgrade. The Company will have an opportunity to provide information concerning CIS at a future proceeding. At that time the cost incurrence for the Legacy upgrade will be better understood. The Board authorizes the Company to establish a deferral account to capture the expenses of the upgrade of the Legacy systems.

3.2.14 Additional one-time expenditures related to Y2K ($6.2 million) and an increase to the IPLE fee ($0.5 million), both discussed below, lead to a total Board-approved 1999 O&M budget of $264.2 million.

3.2.15 The difference between the $264.2 million approved by the Board and the $280.0 million proposed by the Company is $15.8 million. However, the $15.8 million difference is offset by $7.7 million as a result of the restatement of HIP revenues to yield a net adjustment of $8.1 million to the Company's requested 1999 O&M expense.

O&M Presentation

3.2.16 The Board agrees with those intervenors who argued that neither the 1998 O&M estimate nor the 1999 budget could be addressed without considering the effect of the Company's presentation of the unforecast revenues. In fact, it was necessary to review the proposed expenditures separately from revenue items to come to a fair determination of the appropriate budget levels.

3.2.17 While past Board-approved O&M budgets may have contained implicit revenue items, it is the Board's view that the process of reviewing and understanding the Company's application for the funds needed for the operation and maintenance of the utility operations would be greatly improved if the Company were to present only proposed costs in its O&M proposed budget, providing the revenue items separately. The

Board directs the Company to present information in this way at the next rates case, and for consideration in Phase II of this proceeding.

3.2.18 Some intervenors argued that the failure to disclose the then President's memorandum violated the spirit of the settlement process and that, had the intervenors had access to the targets set in the memorandum for each of the 1998 and 1999 O&M budgets, their position in the settlement discussions would have been different, and the outcome might have been affected. The Board does not agree that the targets set in the memorandum indicate that the Company could live with much lower O&M budgets than it was prepared to disclose to the Board and parties to this proceeding. The Company must be able to set targets internally which reflect those aspects of the budget which are within the control of the individual departments and provide a basis for developing individual departmental budgets prior to the global adjustments required for such items as non-utility eliminations.

3.2.19 A number of intervenors noted that it is very important to determine an appropriate level for the O&M budget for fiscal 1999, since it will form the base budget for the Company's proposed incentive mechanism in Phase II of this proceeding. The Company has agreed that some proposed items of expenditure such as the Y2K O&M expenses and the upgrades to the Legacy customer system should be viewed as one time costs, and not as part of the base for the purposes of Phase II. The Board agrees with intervenors that any overstatement of the base would be unusually beneficial to the shareholder, given that it would provide over-earnings for the duration of any incentive mechanism that was approved. The exact amount of the base O&M for the purposes of a performance-based mechanism will be the subject of consideration in Phase II, should this remain an issue.

3.3 Y2K EXPENDITURES

3.3.1 As the year 2000 approaches, concerns have increased among businesses and governments throughout the world about the so-called "Year 2000 ("Y2K") Problem". The expected difficulties stem from the technical inability of most information system technology and embedded systems to recognize the date change to the new century, having been set up to recognize year dates based on two digits, rather than the four needed to make the transition from twentieth century dates to those beginning in year 2000.

3.3.2 While the issue has a technical origin, its implications are wide spread, and the solutions needed are multifaceted. Possible technical malfunctions may result in equipment and infrastructure failure, process breakdown, supply interruptions, and other results which may lead to legal and financial consequences. In a survey published in February 1998, Statistics Canada found that only about 50% of businesses in Canada were addressing Y2K challenges, and Industry Canada's Task Force Year 2000 report based on the survey identified the problem as *"a matter of national importance"*. The Conference Board of Canada confirmed that the Y2K challenge could have a significant negative impact on the Canadian economy.

3.3.3 The Board takes notice of a follow-up report issued in July 1998 by the Task Force which found that *"despite significant improvements in Canadian business preparedness since October 1997, the situation is still serious. The national supply chain remains vulnerable"*. The report specifically indicated concerns with the level of preparedness of the transportation, communication, and utilities sectors, industries which the Task Force viewed as *"mission critical to the national economy"*. In the Report's words *"these industries are so significant to others that if they are not adequately prepared, they could cause considerable disruptions in our economic and social systems. The fact that 24 percent of large firms in the utilities sector...do not expect to be ready until after June 1999 is a very serious concern"*.

3.3.4 Evidence provided to the Board in E.B.R.O. 495 indicated that the Company was aware of some of the potential Y2K problems, and anticipated that the development of its SIM projects, and the anticipated completion of CIS, would address many of them. The Company had included in its 1998 capital budget an amount of $2.5 million and $2.3 million in the 1999 capital budget as originally filed. It is now clear, and the Company accepts, that the extent of the problem was not well-understood at that time.

3.3.5 The Company now proposes to spend a total of almost $22 million on Y2K related projects. In June 1997 the Company assembled a project team to determine the magnitude of the effort involved in becoming Year 2000 compliant, but as a result of the recommendations of a consultant's business risk assessment in the fall of 1997, the Company realized that a much more comprehensive approach was necessary, and initiated a "larger scale program with a corporate wide focus". By March 1998, a revised estimate of the costs of the program were filed. The following table of costs was presented by the Company:

COSTS OF THE Y2K PROGRAM OFFICE		
	1998 ($000)	**1999 ($000)**
Supervisory Salaries	1,700	5,000
Employee Benefits	170	500
Contractors	1,200	1,500
Conversion Automation	1,000	1,000
Infrastructure (IT)	2,000	1,800
Infrastructure (Non-IT)	500	500
Testing & Implementation	500	1,700
Bus. Unit Conversion & Testing	800	2,000
Total	**7,870**	**14,000**
Source: Exhibit D1/T11/S2 p6, corrected		

3.3.6 The amounts relating to infrastructure, both IT and non IT, are capital amounts. The remainder, \$5.37 million for 1998 and \$11.7 million for the test year, are O&M costs, within which \$1 million and \$1.5 million, respectively, relate to the remediation of the Legacy customer systems required as a result of the delay in CIS. No O&M costs were budgeted for fiscal 1998 in the E.B.R.O. 495 rates review.

3.3.7 The Company has established a program office to coordinate its Y2K remediation efforts, staffed by 50 Company employees and approximately 20 contractors. Although the salaries of the employees are included in the Y2K program office budget, these salaries have not been removed from the departments from which the employees have been "borrowed", on the assumption that those departments will need to backfill the positions. To the extent this assumption is incorrect, there will be a reduction in the required costs of the Y2K program, since the program will not be charged for employees whose departments do not replace them. The Company is seeking a deferral account relating to the \$5.37 million estimated O&M expenditures in 1998, and a variance account to allow for the uncertainties in estimating the $11.7 million of 1999 O&M costs.

3.3.8 A number of issues were raised relating to the Company's proposed Y2K expenditures. At the most general level is the issue of the need for the expenditures, and the extent to which the program undertaken by the Company is in line with those of other similar industries, adequate, and well thought out. More particularly, there is an issue of the extent to which the expenditures have been occasioned by the delay in CIS, or by inadequate anticipation by the Company's management of Y2K problems. With respect to the particular expenditures, the extent to which they are capitalized or expensed, and the reasonableness of the forecast amounts are in issue.

3.3.9 Given the seriousness of the consequences of an industry unprepared for Year 2000, as highlighted in the *Task Force Year 2000 Report*, the Board has no doubt that the Company requires a serious and intensive Y2K program if it is to achieve even substantial compliance by the close of 1999. The Company acknowledged that it, like most other organizations, did not have a complete understanding of the problems and their implications a year ago, and identified $1.5 million in test year proposed expenditures as resulting from the CIS delay. It does appear, however, that the Company understood at least some of the complexities of Y2K as early as the summer of 1997, although it was not until the delay in CIS was certain that increased funding for Y2K was proposed. It is understandable that some intervenors have argued that all Y2K expenses stem from the CIS delay.

3.3.10 While one might speculate that a completed CIS would have obviated more of the proposed expenditures, or criticize the Company for its complacent confidence that it was addressing the problems adequately through SIM, it is clear that money must now be spent quickly and wisely to prepare for Year 2000. What is not clear is the extent to which the forecast amounts are reasonable, and the extent to which the costs should be borne by ratepayers. Employee expenses in particular raise a question; they have been budgeted as if back fill will be required in every instance in which a department lends an employee to the Y2K program, with the understanding that a correction will be made if backfilling is not required. In the meantime, the budgeted amounts for both the department and the program would be included in rates. The Board is not satisfied that such an approach yields "just and reasonable" rates.

3.3.11 The Company has argued that it is "dedicated and determined to prevent Y2K issues from impacting its customers." The Board applauds this approach, but believes that there is an issue as to whether some of the costs might reasonably be borne by shareholders, a circumstance that will no doubt prevail in unregulated companies, and act to reduce expected rates of return for those companies. The Board does not agree with the Company's implication that in a regulated company the shareholder should necessarily be insulated from all risks of this unusual problem.

3.3.12 As the Board has noted elsewhere, the lack of information provided by the Company on the reasons for the CIS delay lead the Board to conclude that the Company has not met the onus to support the inclusion of costs related to the CIS delay in rates. The Board therefore disallows the $1.5 million identified by the Company as CIS related costs. In addition, in light of the "double counting" for staff, and the fact that the Company could have acted earlier, given the state of its knowledge in the summer of last year, and might therefore have required a lower level of expenditure, the Board further reduces the O&M portion of the program expenditures by $4 million. The Board therefore accepts O&M expenditures of $6.2 million relating to Y2K for the purposes of setting rates for the test year.

3.3.13 The Board also notes that the Company has acknowledged the one-time nature of the costs related to Year 2000 compliance. Given the Company's intention to seek approval for performance-based regulation in relation to the O&M expense component of its costs of service beginning in the year 2000, a suitable baseline O&M will need to be established in Phase II of the proceeding. The Board emphasizes that Y2K O&M costs will not form part of the base expenditures for that purpose.

3.3.14 As noted above, the Company requested the Board to establish a deferral account to record 1998 O&M costs related to Year 2000 expenses. The Company also requests that the balance in the account be recovered from ratepayers. For 1999, the Company proposes to capture the variance between the actual and budgeted 1999 Y2K O&M costs in the 1999 Y2K Variance Account, to be brought forward for disposition in the next main rates case. The Company bases its requests for these accounts on the uncertainties inherent in predicting all aspects of Y2K problems and the eventual cost to address them.

3.3.15 As the Board discusses in Chapter 5, in future additional considerations will apply to requests for, and dispositions of, deferral/variance accounts in-year, and those proposed for a future fiscal year. For the present, the Board authorizes the Company to establish both the 1998 Y2K deferral account and the 1999 Y2K variance account for these unusual and difficult to forecast expenditures. The Board, however, does not authorize clearance of the 1998 account. Rather, the balance should form the opening balance of the 1999 account, which will be disposed of as determined by the Board in the next main rates case.

3.4 IPLE MANAGEMENT FEE

3.4.1 In E.B.R.O. 495 the Board approved a management fee for services from IPLE of $500,000 for fiscal 1998 compared to $1.3 million requested by the Company. The Board directed the Company to provide in its next rates case justification of, and to quantify to the degree possible and practical, the management fee to be paid to IPLE.

3.4.2 In the current proceeding, the Company proposed a fee of $2.3 million for 1999, an increase of $1.0 million from the 1998 proposed amount and $1.8 million from the Board-approved amount. The proposed amounts for each of the services to be received by Consumers Gas and the Company's calculations of the benefits are shown in the table below.

1999 IPLE MANAGEMENT FEE - PROPOSED COSTS AND BENEFITS				
Services	**Cost ($000s)**	**Direct Benefits ($000's)**	**Synergy Benefits ($000's)**	**Total Benefits ($000's)**
Corporate Law	292	145	200	345
Corporate Secretarial	202	200		200
Board of Directors	91	200		200
Controllers	42	0	202	202
Pension Fund Management	289	289		289
Investor Relations	404	404		404
Aviation	130	105		105
Human Resources	334	75	100	175
CEO	153	153		153
Energy Distribution	362	362		362
TOTAL	**2,299**	**1,933**	**502**	**2,435**
Source: Exhibit D1/T8/S2				

3.4.3 Intervenors' concerns centered around the lack of information regarding IPLE's total cost pool and amounts allocated to other IPLE affiliates, and the appearance of unfair sharing of synergistic benefits arising from the provision of the services. Specific services and costs were also contested by certain intervenors.

3.4.4 Given the more extensive evidence filed in this proceeding in response to the Board's direction in E.B.R.O. 495, the Board has conducted its review based on a zero base approach rather than starting with the amount allowed in 1998 and the services which were found to be useful for utility service in that test year.

3.4.5 The Company argued that it had satisfied the criteria which the Board had applied in E.B.R.O. 493/494 in its review of the proposed payment of Westcoast Corporate Centre Charges by Union Gas Limited and Centra Gas Ontario Inc. These were: the services are required by the utility; the costs were appropriately allocated to the utility; and the benefits to the utility exceeded the costs.

3.4.6 The Board shares intervenors' concerns that, given IPLE's refusal to provide sufficient information for the Board to assess the reasonableness of the costs incurred by IPLE and the allocation of such costs to Consumers Gas, it is difficult for the Board to ascertain reasonableness of the fee amount on the second criterion above. The Board has no authority over IPLE, and finds that Consumers Gas has not met the onus upon it to prove the reasonableness of these fees. However, that is not a sufficient reason to disallow the full fee amount as proposed by some intervenors. Rather, from the evidence available the Board's findings are set out below.

3.4.7 The Board finds that in general IPLE costs related to the governance of Consumers Gas are a shareholder cost of managing its investment and are not a cost which should be borne by the utility ratepayers. The rates paid by ratepayers include an allowance for a fair return on shareholders' equity and the shareholder also stands to benefit in the longer term from gains in share price. The Board considers that the costs of managing the IPLE investment in Consumers Gas are part of the costs of any similar shareholding and, consistent with the Board's prior Decisions, are not recoverable in rates. In addition, the Board notes that one of Consumers Gas' executives is listed as Corporate Secretary within the organization charts filed with the Board. Therefore the Board finds that the combined amount of $293,000 for IPLE Board of Directors and Corporate Secretarial functions is a shareholder cost.

3.4.8 With respect to CEO and Energy Distribution costs (IPLE executive management costs), the Board is not convinced by the evidence that these services are required by Consumers Gas for management of its core utility operations as opposed to other Company activities such as the diversification, business development and corporate reorganization of The Consumers' Gas Company Ltd. The Company has twenty-one senior executives responsible for its operations, with considerable experience in the transmission, distribution and supply of gas to the Company's 1.4 million customers. The Company and IPLE have not proven to the Board's satisfaction that the CEO or Energy Distribution role at IPLE are essential to the efficient operation of Consumers Gas' regulated services and that this extra layer of management adds value for gas ratepayers. The Board therefore finds that none of the combined proposed costs of $515,000 for IPLE executive management services shall be recovered from utility ratepayers.

3.4.9 While the Board makes no specific adjustment to the costs for Investor Relations services, the Board observes that these services also support IPLE equity issues, and that there is potential overlap with Treasury services for which a separate approved fee of $922,000 is payable in 1999.

3.4.10 For the remaining services, the Board has applied the principle that the costs to the regulated utility must be less than or equal to the benefits. The Board discounts the claimed synergy benefits on the basis that these are indirect and have an insufficient link to utility cost savings.

3.4.11 The Board notes that the remaining proposed costs total $1,491,000 and the direct benefits $1,018,000. The Board therefore approves for ratemaking purposes a fee of $1 million for 1999, $0.5 million over the amount approved in 1998.

Undertakings Approvals

3.4.12 The affiliate transaction involving the IPLE Management Fee was originally approved by the Board without a hearing following an application pursuant to Article 5.1 of the Company's Undertakings under Board File number E.B.O. 179-05. The Board's approval letter dated November 17,1995 stated in part:

> *"Consumers Gas is seeking the Board's approval, without a hearing, to pay a management fee in excess of $100,000 annually commencing fiscal 1995. The proposed management fee is $300,000 in fiscal 1995, and $400,000 in fiscal 1996. Management fees were not included in the Company's proposed cost of service in either E.B.R.O. 487 or E.B.R.O. 490; however, the Company stated that it may seek to recover management fees for future fiscal periods in the Company's rates.*
>
> *The Board approves the requested exemption from the Undertakings without a hearing for fiscal 1995 and fiscal 1996. Should the Company intend to continue this transaction in fiscal 1997, the Company will need to demonstrate that the benefits to Consumers Gas are in excess of the costs."*

3.4.13 The evidence indicated that the Company had paid to date, or was proposing to pay, certain amounts while the Board in E.B.R.O. 492 and 495 had approved other amounts for recovery in rates:

IPLE MANAGEMENT FEES					
Year	**1995 ($000)**	**1996 ($000)**	**1997 ($000)**	**1998 ($000)**	**1999 ($000)**
Amount paid/proposed	350	350	1222	2230	2299
Board Approved for recovery	0*	0*	425 (EBRO 492)	500 (EBRO 495)	1000 (EBRO 497)
*no rate case approval of a specific amount					

3.4.14 The issues of the Company's interpretation of the Undertakings' requirement for prior approval and the nature of the specific Board approval of the IPLE management fee in E.B.O. 179-05 were the subject of submissions by the parties in response to a Board request. The Company submitted that, once given, the Board's approval under article 5.1 of the Undertakings was ongoing and that in this event there was no restriction on the amount to be paid annually, but only on the amounts to be recovered in rates in each test year. Some intervenors took the position that although technically the Company should not have increased the amounts paid from the original 1995/1996 level without further undertakings approval, nothing turned on this, because ratepayers had paid only the Board-approved amounts in each test year. Others submitted that technically the Company was in breach of the letter of the Undertakings and should not, absent any Board approvals to the contrary, pay IPLE more than the Board-approved rate case amount in any year.

3.4.15 The Company submitted that it would unduly restrict its ability to pursue legitimate means of achieving efficiencies if the Board were to freeze a single O&M line, such as the IPLE management fee for services it receives from an affiliate, merely because it is also an affiliate transaction. The Company argued that such a step would deprive the Company of an important management tool, and that there is no need for a freeze approach, given the Company's overall approach to affiliate transactions including variances.

3.4.16 The Board notes that Article 5.1 requires prior approval of any affiliate transaction aggregating more than $100,000 annually and that, unless the Board's approval is clearly for a recurring transaction with no time limit or for a multi-year period, specific approval each year is required. In the case of the IPLE Management Fee, the Board's approval was for two years (1995 and 1996) with any further years subject to the condition that the Company demonstrate that the benefits to The Consumers' Gas Company Ltd. exceeded the costs.

3.4.17 The Board found in the E.B.R.O. 492 rates case that the quantum of costs which was reasonable based on benefit to ratepayers was $425,000 for 1997. In E.B.R.O. 495 for 1998 the amount was $500,000. The Company did not suggest that there were greater benefits to The Consumers' Gas Company Ltd. as distinct from the regulated utility, or lead evidence as to why they should pay a higher amount than approved for rate making purposes. In addition, from the evidence presently before the Board, it is clear that the nature of the transaction has changed from the 5% management fee applied for in 1995, to encompass a broader range of corporate services for which IPLE is seeking cost recovery from The Consumers' Gas Company Ltd. and which represent "somewhat more" than 5% of IPLE Corporate Centre costs. The Board's letter of approval made it clear that continuation of the transaction (payment of a fee to IPLE) would be allowed only if the Company demonstrated that the benefits exceeded the costs. The Board found that the benefit to the regulated utility was $425,000 in 1997 and $500,000 in 1998. There was no authorization to pay a higher amount than approved for recovery in rates, which was the amount the Board deemed of benefit to ratepayers.

3.4.18 Given the form and nature of the transaction applied for in E.B.O. 179-05 and the Board's specific terms of approval of that application, the Board finds the Company should not have made payments for 1997 or 1998, and should not make future payments to IPLE, in excess of the Board-approved amount, subject to variances within reasonable limits.

3.5 DSM PLAN

3.5.1 In its Decision in E.B.R.O. 487, the Board approved the Company's first DSM plan, a plan which remained essentially unchanged in the next four years. In reviewing the DSM plans in each subsequent rates case, the Board encouraged the Company to broaden and improve its DSM efforts, in consultation with its stakeholders. In E.B.R.O. 495, the Board noted that there was complete agreement amongst the parties to the ADR on all DSM related issues except for the proposed implementation of a Lost Revenue Adjustment Mechanism ("LRAM") and a Shared Savings Mechanism ("SSM"). The Board in its Decision approved the LRAM, but did not accept the SSM.

3.5.2 The capital cost of the proposed 1999 plan is $4.0 million; O&M expenditures are forecast at $5.0 million, $300,000 of which relates to a proposed NGV pilot project.

3.5.3 The following specific issues under the general topic of the DSM Plan remained outstanding following the Settlement Conference: program performance, change in LRAM methodology, compliance with past settlement proposals and the inclusion of the NGV pilot project in DSM. The NGV pilot project issue has been dealt with in Chapter 2.

Program Performance

3.5.4 In the present application, the Company has revised its DSM gas savings targets downward to 32.3 10^6m^3, a target lower than that proposed in either 1997 or 1998. It noted in proposing this adjustment that 1998 results included "anticipated completions of a number of large projects that were initiated during the previous years", while the projections for 1999 " are somewhat lower due to the anticipated long lead times for new projects as experienced by the Company to date".

3.5.5 The Company points out that DSM performance has improved steadily over the three years the plan has been in place, with gas savings increasing almost tenfold since 1995. Cost effectiveness has also improved. In the Company's view, the variance between historical budgeted gas savings and actual savings do not indicate poor performance, but result from the Company's inexperience with delivery of DSM programs, longer-than anticipated sales cycles in the large volume market, and a longer than expected time frame for the development of a market for performance contracting in the industrial sector. The Company expressed confidence in its 1999 gas savings forecast, given its experience and the modifications that have been made to the programs.

3.5.6 The Green Energy Coalition filed evidence prepared by Chris Neme of Vermont Energy Investment Corporation and Philip H. Mosenthal of Optimal Energy which criticized the Company's downward revision of its DSM savings goals. Their report presents evidence that there are significant, cost-effective energy savings available in several 'lost opportunity' markets.

3.5.7 It is GEC's submission that, although the Company does not contest the potential to increase the DSM savings through its programs, it is not prepared to pursue the potential, and that the consultative and alternative dispute resolution processes need to be supplemented by strong direction from the Board to strengthen the Company's corporate commitment to DSM. It points to government policy to encourage energy efficiency as indicated by proposed amendments to the *OEB Act* as further support for efforts to improve DSM performance. Cost benefit analyses indicate that investment in DSM yields substantial ratepayer savings. In this intervenor's view, the Company's informal screening methods do not allow appropriate choice of beneficial programs while minimizing cross-subsidies and limiting rate impacts.

Submissions by other intervenors included:

- There is higher potential for DSM savings in the commercial, institutional and industrial ("CII") sector, compared to the residential sector, given the large proportion of gas throughput for which this sector is responsible, and the cost effectiveness of DSM measures in this sector. More of the Company's DSM efforts should be directed to this sector.

- Water heater energy efficiency programs, which have provided effective DSM savings in the past, may be adversely affected by reductions in average efficiency of the units purchased.

- The approach to DSM in other jurisdictions is undergoing changes as market transformations take place. Given the Company's plans to transfer its ancillary activities outside the utility, the DSM program will need rethinking. Phase II of this proceeding is an appropriate forum for consideration of the future of DSM.

- In the circumstance, spending on DSM should be limited to actual 1998 amounts during the transition, and the Company should concentrate on consolidation and improvement of existing programs, rather than pursuing new initiatives.

- The offering of incentives to industrial customers to enter performance contracts may distort and disrupt energy service markets; incentives should be offered only in exceptional circumstances.

- The Board should direct the Company to complete its negotiations with the City of Toronto and execute an agreement to provide a loan loss insurance fund for losses incurred when energy savings project customers, particularly in the CII sector, cannot repay utility loans.

- The Company should be encouraged to work closely with accredited energy service companies in its DSM program development, particularly through retrofit initiatives.

3.5.8 The Board finds the evidence tendered by GEC that there are untapped potential DSM savings which may be achieved by the Company through more effective screening techniques to be sound and convincing. This is, however, a juncture in the history of gas regulation and DSM in particular at which it does not appear to the Board to be appropriate for the Company to make significant changes in its DSM plan. Both the unbundling initiatives of the Company and the proposed move to incentive based regulation will likely have an impact on the future scope of DSM. The Board will likely be considering these matters in the near future, and is therefore reluctant in this Decision to direct any changes that will have a material effect on the Company's present DSM plan. Given that the only increase proposed in the DSM budget was that related to the NGV pilot project, which the Board has not approved, an essentially "flat-line" approach to DSM budgeting results. This is appropriate, in the Board's view, given pending new legislation and a general state of flux in policies concerning the responsibility for energy efficiency and environmental stewardship.

Compliance with Past Settlement Proposals - Appliance Labeling

3.5.9 As part of the Settlement Agreement in E.B.R.O. 495, the Company agreed to "undertake an industry leadership role in the development of standards for energy rating of natural gas appliances", and in particular to assist in the development of the EcoLogo Program for the labeling of such appliances. The Company also agreed, where appropriate to promote appliances bearing the EcoLogo in its product portfolio. The Company submits that it has honoured this agreement; however, it is the contention of some intervenors that the Company is not living up to these commitments.

3.5.10 The Company's evidence is that it has identified appliances for certification, and initiated the process, which will be completed for priority appliances sometime later this year. A proposal relating to testing of commercial boilers is being prepared. Some intervenors urge the Board to direct the Company to proceed expeditiously with the development of energy efficiency standards for commercial heating, cooling and cooking equipment, to ensure EcoLogo certification of its rental water heaters and to launch an educational program to inform customers of the benefits of purchasing or renting EcoLogo water heaters. Intervenors are concerned that as the water heater rental market changes, opportunities to ensure that consumers are able to make energy efficient choices may be reduced.

3.5.11 While the Board agrees that labeling of appliances may be an effective way to promote energy efficiency, it questions whether labeling of rental water heaters is as effective in promoting the efficient use of natural gas. In addition, the Board notes the Company's plan to discontinue renting water heaters. In the circumstances, the Board is not prepared to require further steps from the Company at this time, but urges the Company to continue its commitment to pursue, together with others in the industry, the development of energy efficiency standards for natural gas appliances.

LRAM

3.5.12 In E.B.R.O. 495 the Board authorized the creation of a Lost Revenue Adjustment Mechanism, which captures the increase or decrease in the Company's margin resulting from variations between forecast and "actual" Demand Side Management savings. Actual savings in this context refer to estimates of savings using more recent information.

3.5.13 The proposal is to fix the "actual" savings per participant at the level filed at the hearing rather than having to determine them on a regular basis. The margin variations in LRAM would therefore be the result of variances in the number of DSM participants only. This change would apply to DSM programs utilized by small volume participants, such as residential customers. The per participant impacts of large volume customer DSM programs will continue to be determined using an assessment of participant-specific information. The evidence revealed that the proposal would create certain consistencies with the Company's proposed Shared Services Mechanism to be included in the Company's filing for Phase II. An SSM was proposed by the Company and was rejected by the Board in E.B.R.O. 495.

3.5.14 Intervenor positions were mixed on this issue. CAC and Pollution Probe accepted the proposal. GEC suggested that the proposal be accepted on a provisional basis until the Board decides on the SSM, while IGUA suggested that the matter be deferred until the Board decides on the SSM. The Alliance and the Schools argued that using more up to date information is more appropriate.

3.5.15 The Board accepts the Company's proposal on two grounds. First, the proposal appears to introduce simplicity in measuring the variation in margins recorded in the LRAM account. The current method requires time and effort on the part of the Company on a monthly basis to estimate the savings per participant. The Board accepts the Company's argument that, for the DSM programs utilized by small volume participants, the balances recorded in LRAM are largely due to variations in the number of participants, not variations in the savings per participant. Also, testing of the balances in the LRAM account for regulatory review purposes appears to be simplified.

3.5.16 Second, the Board agrees with the Company that, from an operational perspective, acceptance of the proposal at this time, with the possibility of a review if necessary following the Board's decision on the SSM in Phase II, is preferable to a deferral of the matter. In coming to this conclusion the Board considered that, in the event of a possible reversal, this is not a matter that would require communication to customers. A common theme for the parties' opposition to the proposal is its link to the SSM. The Board cautions that its acceptance of the change to the LRAM methodology should not in any way be viewed as an endorsement of the SSM proposal which, should it remain an issue in Phase II, will be decided on its own merits.

3.6 CAPITAL BUDGET - 1998

3.6.1 The estimated capital expenditures for fiscal 1998 total $366 million, an overage of $23.4 million from the capital budget amount approved by the Board in E.B.R.O. 495.

3.6.2 The table below shows the variances between the 1998 capital expenditure estimates and the Board- approved figures for each category. In its prefiled evidence, the Company noted that 93.2%, or $21.8 million, of the overage in total capital expenditures for 1998 could be attributed to customer related distribution plant and rental equipment on customers' premises. These additional expenditures, according to the Company, resulted from much stronger than anticipated economic activity leading to estimated 1998 customer additions 16.2% higher than the Board-approved forecast. The remainder of the 1998 variance from budget was attributed mainly to project timing differences.

COMPARISON OF UTILITY CAPITAL EXPENDITURES ESTIMATED 1998, BOARD-APPROVED 1998 AND FISCAL 1999				
	($millions)			
	Estimate 1998	Board-Approved Budget 1998	Est 1998 Over/(Under) Budget 1998	Budget 1999
Customer Related				
Sales Mains	44.8	31.9	12.9	52.0
Services	52.3	45.6	6.7	57.1
Meters & Regulation	20.3	23.6	(3.3)	22.3
Sub-total Customer Related Distribution Plant	117.4	101.1	16.3	131.4
Rental Equipment on Customers' Premises	104.3	98.8	5.5	94.9
	221.7	**199.9**	**21.8**	**226.3**
System Improvement and Upgrades				
Mains- Relocations	6.0	4.7	1.3	3.0
- Replacement	18.6	18.5	0.1	22.8
- Reinforcement	11.3	10.3	1.0	5.6
Sub-total Mains	35.9	33.5	2.4	31.4
Services - Relays	19.0	19.5	(0.5)	19.5
Regulators - Refits	3.8	5.2	(1.4)	4.5
Measurement and Regulation	8.0	7.7	0.3	7.5
Meters	6.9	5.5	1.4	5.3
	73.6	**71.4**	**2.2**	**68.2**
General and Other Plant				
Land, Structures, and Improvements	9.1	9.1	-	11.0
Office Furniture and Equipment	1.5	1.9	(0.4)	2.1
Transp/Heavy Work/NGV Compressor Equip.	3.4	3.4	-	4.5
Tools and Work Equipment	1.5	1.5	-	1.6
Computer and Communications Equipment	36.9	36.1	0.8	36.4
	52.4	**52.0**	**0.4**	**55.6**
Strategic Information Management	-	-	-	-
Underground Storage	18.3	19.3	(1.0)	12.9
	366.0	**342.6**	**23.4**	**363.0**

Source: Exhibits B4,T2,S2; J1.1 [COL2: B4T2S2; COL3: B4T2S2]; and B3T2S1 updated 98-06-13.

3.6.3 In E.B.R.O. 495, at paragraph 3.2.13, the Board expressed concern that "a Board-approved capital budget amount is nothing more than a rate setting device" and noted that the constant upward pressures on rates resulting from overages in the Company's capital spending must be better managed. To this end, the Board stated that:

> *"...for ratemaking purposes, any expenditures above the overall Board approved levels in each of the main categories of the capital budget shall not automatically be included in the Company's proposed rate base for fiscal 1999."*

3.6.4 The Board directed the Company to treat each category of capital expenditure as an "expenditure envelope" and directed the Company to present appropriate information to the Board with respect to any overage within an envelope in order to confirm the amounts for both accounting and regulatory purposes.

3.6.5 The overage in 1998 capital expenditures for customer related distribution plant and rental equipment is the very type of expenditure which was the subject of the Board's concerns as expressed above. Notwithstanding the Board's comments in E.B.R.O. 495, the Company included the overage in its determination of the 1998 Bridge Year rate base, and subsequently in its 1999 Test Year rate base. In justifying this treatment of the overage, the Company stated "The Company is committed to minimizing capital budget variances where possible and appropriate, but must respond to customer demands for service and does so within Board Approved feasibility guidelines". Customer additions in 1998 were forecast to be almost 7,600 higher than had been forecast in the Board Approved budget for 1998, and the resulting increased capital expenditures were included by the Company in determining its rate base "based upon the prudence of the expenditures, which were primarily driven by the need to provide service in response to customer demand".

3.6.6 In E.B.R.O. 495, the Company filed a Capital Budget Variance Study, and, as part of the ADR, committed to take steps to reduce variance in capital expenditures. In its prefiled evidence, the Company described a number of specific steps it had taken to satisfy this commitment.

3.6.7 In response to questions as to how this commitment could be reconciled with the substantial variance in 1998 capital spending, the Company's witnesses stated that the commitment related to those types of capital expenditure which were amenable to the

Company's control, such as the timing of the completion of capital projects in relation to the fiscal year end; market demand for natural gas service as a result of good economic conditions was not controllable, nor should it be the subject of spending restraint.

3.6.8 CAC questioned whether the Company ever intended to abide by its agreement, given the Company's longstanding approach to unbudgeted system expansion, and that such behaviour on the part of the Company undermines the settlement process.

3.6.9 The Company's witnesses stressed the Company's view that "the economics of the investment should be the key driver in the decision about when to proceed with projects to serve new customers", and that the feasibility and rate impact tests used by the Company to screen capital spending projects would protect the interests of existing customers from undue cross-subsidization of new customers. They described the Board-approved budget as "an operating plan and control tool [which] should be flexible to accommodate changes in demand, especially with respect to customer additions and the related capital which are sensitive to changes in economic conditions".

3.6.10 The table below shows capital expenditures on customer related plant (excluding rental equipment), from 1995 to the test year, with actual expenditures indicated for 1995, 1996 and 1997, and estimated and forecast expenditures for the 1998 bridge and 1999 test year respectively.

3.6.11 It is the Company's evidence that 1997 was an unusual year, with customer additions increasing unexpectedly by about 20% over the forecast and that this dramatic increase was not fully understood by the Company at the time it prepared its 1998 forecast.

CUSTOMER RELATED CAPITAL EXPENDITURES				
Year	**Forecast Customer Additions**	**Actual Customer Additions**	**Capital Cost (millions)**	**Overage (millions)**
1995	42,818	44,408	$98.70	$16.70
1996	45,005	45,830	$108.80	$11.50
1997	45,005	54,670	$115.80	$25.00
1998	46,906	54,494	$117.40	$16.30
1999	53,453	n/a	$131.40	n/a
Source: Exhibits B5/T6/S2, B5/T7/S1, B4/T2/S2, B4/T2/S5, B3/T2/S1, B3/T2/S3.				

3.6.12 According to a Company witness, rate impacts in evidence in E.B.R.O. 495 "made it appear as if the expansion program was causing rate impacts on the order of two per cent or three per cent or four per cent per year and so...it's no wonder that the Board had such a high degree of concern with the program". The rate impact of the Company's investment portfolio for the 1999 test year is estimated to be approximately 0.14% or an approximate added cost of $1.85 per customer.

3.6.13 As noted above, during the hearing, a memorandum to senior managers from then Company President R.D. Munkley was provided in response to a request from intervenors for background documents to the Company's budgeting process. This memorandum, prepared a few weeks after the Board's E.B.R.O. 495 decision was released, revealed information on the Company's approach to forecast customer additions. Although the Board, as noted above, had expressed concerns about unbudgeted capital spending, and had based its decision on the Company's 1998 forecast of approximately 47,000 additional customers, the memorandum stated: "Achieving earnings growth will require continued system expansion and the additions of new customers, both of which require capital expenditures", and directed management to "[a]chieve customer additions targets of ***54,500*** in 1998" (emphasis added).

3.6.14 Certain intervenors argued that the Company should find additional capital for customer additions from other parts of its capital budget, that all capital spending over the approved budget of all types, not just that which is customer related, puts upward pressure on rates, and that the Board should disallow some rate base addition associated with the 1998 overage.

3.6.15 Given the assurances that rate impacts of the capital expansion program are indeed less than formerly reported, the Board is prepared to accept into rate base the over-expenditures of the 1998 capital budget, most of which relate to system expansion. The Board feels impelled to comment, however, about the process of approving capital budgets for a test year.

3.6.16 The Board questions the value of the time and effort spent reviewing the Company's proposed capital budget. Its recent track record demonstrates that the Company has not been able to stay within Board-approved amounts. In addition, Consumers Gas appears to have little regard for Board-approved forecasts of customer additions. The Board addresses this problem below in its discussion of the 1999 proposed capital budget and the issue of whether or not a "cap" on capital expenditures is appropriate.

3.7 CAPITAL BUDGET - 1999

3.7.1 The components of the proposed 1999 capital budget are also shown in the table comparing utility capital expenditures. The proposed capital spending for Y2K has already been addressed in conjunction with Y2K O&M costs. The issues addressed in this section include: the proposed capital expenditure relating to the roll-out of the Customer Information System; the proposed new Feasibility Policy for the implementation of the E.B.O. 188 System Expansion Guidelines; the extent to which a Board-approved capital budget should act as a constraint on the Company's capital spending in the event that actual business, economic and market conditions vary from the corresponding assumptions underlying the Board-approved capital budget, and the capitalization of Administrative and General overheads.

CIS Expenditures

3.7.2 As noted in Chapter 1, the Company has postponed its application for approval of affiliate transactions relating to its CIS. The CIS was the subject of the Board's consideration in E.B.R.O 495, during which proceeding it was the Company's evidence that the CIS was being obtained from Price Waterhouse and was expected to be in service for rate making purposes in the 1999 fiscal year. The in-service date has been delayed.

3.7.3 Notwithstanding the uncertainty as to the completion date for the CIS, the Company proposed a capital expenditure of $300,000 in the last quarter of the test year to facilitate the roll-out of the CIS early in fiscal 2000. In response to arguments by the intervenors, however, the Company withdrew its request for approval for this expenditure. The Board accepts the Company's withdrawal but, given the minor impact on the 1999 total revenue requirement (about $5,000), has not considered it necessary to adjust the financial schedules in the Appendices.

System Expansion

3.7.4 Capital expansion projects in the Company's original filing were not evaluated on the basis of the portfolio approach set out in the Board's E.B.O. 188 Report. An update filed at the outset of the hearing provided evidence concerning the impact of the new approach. This filing included a new draft "Feasibility Policy Incorporating the E.B.O. 188 Report of the Board" ("Feasibility Policy") which was sent to the Company's field offices. The regions re-evaluated the 1999 system expansion plan and customer periodic contribution charges ("PCCs") based on the Guidelines.

3.7.5 The results were presented in the form of a listing of major projects over $500,000 and an overall distribution system expansion Investment Portfolio for the test year. The latter is summarized in the table below.

1999 DISTRIBUTION SYSTEM EXPANSION INVESTMENT PORTFOLIO	
	Investment/ Cash Flow
Capital Expenditure	
New mains	$34,511,103
Services	$51,974,059
Meters and regulation	$19,180,954
Allowance for O/H and reinforcement	$26,492,076
Total capital	**$132,158,192**
Cash Flows	
Annual revenue from capital additions	$45,918,718
Operating expenses	($31,981,810)
Operating cash flow before taxes	**$13,936,908**
Income tax before tax shield from interest and CCA	($6,071,318)
Operating cash flow after tax before allowance for tax shield	**$7,865,590**
Present Value (PV) Calculations	
PV at beginning of year of revenues for revenue horizon	$114,955,652
PV of tax shield from CCA	$21,921,378
PV of total cash flows	**$136,877,029**
PV of capital investment	($128,067,719)
Net PV from investment portfolio	**$8,809,310**
Profitability Index (PI) of Investment Portfolio	**1.07**
Source: Adapted from Exhibit B2/T5/S4	

3.7.6 The Company stated that the re-evaluation of its 1999 system expansion plan under the Guidelines had not resulted in any increase in overall customer-related capital expenditures for the test year. The primary changes were that some projects previously requiring a contribution would now be included in the test year portfolio without contribution. Otherwise, the change in feasibility input assumptions, such as the reduction in the residential customer revenue horizon from 55 to 40 years, appeared to have offset the ability to include projects with a profitability index ("P.I.") below one.

3.7.7 For listed major projects over $500,000 comprising approximately $16 million in capital investment, or about 12% of the total portfolio, the requirement for customer contributions was about $1.5 million lower with the new guidelines and a minimum threshold project P.I. of 0.8 rather than 1.0.

3.7.8 Although the Company plans to determine if it will discontinue or rebate the PCC for historic projects that now meet the new project feasibility threshold P.I. of 0.8, it has not taken action in this regard to date. The Company stated that it is awaiting the outcome of discussions with Union Gas Limited on a common set of customer connection policies before reassessing the impact on existing customers paying PCCs. The Company will bring forward a proposal in the next rates case which will cover the appropriate regulatory adjustments to wind down the existing PCC program if that is the result of discussions on customer connection policies. Meanwhile the PCC payments to be collected on existing projects are included in the proposed budgets for 1999.

3.7.9 The Company indicated that it would update its Feasibility Policy later in 1998 in time for its use for the next system expansion plan. The updates will include new customer connection policies and new environmental screening guidelines for proposed projects included in the investment portfolio, which will be developed in conjunction with Union Gas Limited. In addition the Company expects to make its System Expansion Rolling Project Portfolio operational in fiscal 1999 and this will then become the internal management tool for all system expansion capital projects for the year 2000 and beyond.

3.7.10 The Company requested Board approval of its Feasibility Policy as an acceptable template for application of the E.B.O. 188 Guidelines to the test year system expansion capital plan.

3.7.11 The Board finds that the Company should apply the new customer connection policies and environmental screening criteria to projects planned for the next investment portfolio or coincident with their application by Union Gas Limited to its system expansion portfolio, whichever is the sooner.

3.7.12 The Board also finds that to improve the efficiency of the public review of system expansion plans in future, the Company should address the following in accordance with the Board's E.B.O. 188 Guidelines:

- a complete set of administrative policies related to the development, presentation and monitoring of its system expansion portfolios;
- a simplified presentation of its system expansion investment portfolio and its rate impacts, including supporting schedules for key variables, a list of important assumptions and explanatory notes on methodology;
- the provision of historic and bridge year comparison reports for the investment portfolio(s); and
- a report on the Rolling Project Portfolio at mid year during the bridge year.

3.7.13 How the new E.B.O. 188 reporting basis relates to the Company's past performance reporting is a matter for the Company to consider. The Board expects that during the transition adequate links to the previous monitoring and reporting framework such as that filed in this proceeding at Exhibit B2 Tab 3, will be maintained.

"CAPPING" OF CAPITAL EXPENDITURES

3.7.14 As noted above, one of the underlying issues relating to capital expenditures in general was the extent to which a Board-approved capital budget should act as a constraint on the Company's capital spending in the event that actual business, economic and market conditions vary from the corresponding assumptions underlying the Board-approved capital budget. The Board had expressed its concern in the E.B.R.O 495 Decision that continued system expansion may place undue upward pressure on rates. In addition, the Board questions the usefulness of examining the Company's forecast capital expenditures in detail in a rates case, making findings as to the appropriate level of capital spending for the test year, and then being asked to approve over expenditures in the next rates case. Not only do the successive reviews require extensive filing of evidence and occupy valuable hearing time, but the value of the Board's determination of a forecast capital budget for the test year must be questioned if it is not used in managing the Company's capital expenditures.

Customer Related Capital Expenditures

3.7.15 Given its findings above in relation to the implementation of the E.B.O. 188 Guidelines, the Board, in approving the investment portfolio of the Company, would implicitly approve the forecast number of customers arrived at through the portfolio analysis. This forecast of system expansion activity would in turn drive the next fiscal year's capital budget, and the Company's implementation of the proposed investments would be monitored through the E.B.O. 188 mandated processes. The Board believes it is important to give this new approach a fair trial, to see how it works in providing the correct level of oversight of the Company's expansion program and its rate impacts. As a consequence, the Board is prepared to accept the 1999 forecast customer related capital expenditures, and await the outcome of the monitoring process. Should the monitoring process be successful, it is possible that prospective review of the Company's proposed customer related capital expenditures will no longer be necessary; a single review of them when additions to rate base are proposed should suffice.

3.7.16 The Board notes, however, that the P.I. proposed by the Company for the test year is only 1.07, and is concerned that this may be too low to prevent undue rate impacts from marginal projects. Although prepared to accept the proposed portfolio for the test year, the Board expects that the Company will use a P.I. of 1.10 as a design target for the future.

Non-Customer Related Capital Expenditures

3.7.17 In its E.B.R.O 495 Decision, the Board found that an "envelope approach" to the various categories of capital spending was an appropriate way for the Company to control its capital spending. The Board has noted above that it may not be necessary to undertake a prospective review of customer related capital if the monitoring process provides sufficient confidence that proposed spending levels are appropriate. With respect to non customer related expenditures, the Board approves the proposed levels for fiscal 1999, and notes that all expenditures must be justified retrospectively if they are to form part of the rate base for the next fiscal year.

3.8 CAPITALIZATION OF ADMINISTRATIVE & GENERAL OVERHEAD

3.8.1 The Company stated that administrative and general overhead ("A&G O/H") related to constructed capital assets are capitalized to ensure that all costs associated with constructing a capital asset, including those related to administrative and general support activities, are included as part of the asset's cost. These costs are then recovered from ratepayers through depreciation of the asset, resulting in a matching of costs incurred and the timing of the benefits they generate. The methodology for capitalizing such costs, last reviewed in 1993, was updated for this application because:

- review every 3 to 5 years is necessary to ensure the methodology continues to accurately reflect the nature of administrative and general activities and their relationship to the construction of capital assets;
- the Company has recently reorganized, and the impact of this reorganization and the changing nature of the business on the practices in this area needed to be assessed; and
- the Company identified a possible double allocation of costs attributed to ancillary programs through capitalization of this type of expenditure.

3.8.2 Historically, the Company estimated the total dollar amount of A&G O/H to capitalize at 12% of the Information Services costs and 20% of the A&G accounts. The pool of capitalizable A&G O/H was allocated to specific constructed capital accounts (furnace rentals, NGV stations, NGV cylinders, water heater rentals, gas distribution, storage development and software applications) based on the relative level of capital expenditures for the accounts in the fiscal period. Such a methodology assumes that each category of constructed capital expenditures attracts A&G O/H at the same rate.

3.8.3 The study undertaken for the test year reviewed and formalized the definitions of a capitalizable A&G O/H activity using the Cost Allocation Study undertaken for Ancillary and Non-Utility programs to gather the information required. This resulted as well in resolving the potential double allocation problem which had been identified relating to these programs. Based on the findings of the study, the Company recommended that costs associated with the customer attachment group be charged directly to capital, as these costs relate solely to gas distribution capital asset additions. The remaining pool of A&G O/H costs to be capitalized were certain amounts from accounts relating to Administrative and General costs, Fringe Benefits and Human Resources, and Information Technology.

3.8.4 The total capitalizable A&G O/H was allocated to six constructed asset group accounts based on the results of the activity analyses submitted by department managers. The result is an 84% allocation to gas distribution and 10% to ancillary programs compared to 58% and 36%, respectively, using the historic method. The Company stated that the shift is reasonable given the relative level of complexity of constructing these two types of assets.

3.8.5 The Company requested that the Board approve the proposed methodology for implementation in the test year. The impact on the 1999 cost of service, other than the shift in the distribution of capitalized O&M between the constructed capital asset groups would be a slightly lower overall level of total A&G O/H capitalization of $23.86 million and an increase in O&M of $0.5 million, partially offset by the impact of the resulting decrease in rate base.

3.8.6 The primary impact of the new methodology was a $6.5 million reduction in the amount of ancillary program capitalized overhead, and a corresponding increase in the distribution related capitalized overhead. Other changes resulted to the storage related capitalized overhead.

3.8.7 Some intervenors argued that there was insufficient evidence to justify the change in allocation at this time, that the resulting shifting of costs from ancillary programs to the utility should not be accepted prior to unbundling, that the methodology is in any case flawed and should be reviewed by an independent assessor, and that the historical method is more appropriate. The Company responded that it had no ulterior motive in proposing the changes now and that the changes need to be made to respond to the "double counting" problem.

3.8.8 The Board accepts in principle that a specific allocation of capitalizable A&G O/H to each constructed capital asset group is superior to a pro rata allocation based on capital expenditures, provided the underlying methodology is accurate, understandable, and cost-effective. However, the linking of the study to the cost allocation activity analyses, although efficient from a management time perspective, may have transferred some of the inherent problems in the new cost allocation method to the capitalization study. The Board believes that the lead responsibility for the capitalization study should rest with the accounting studies group which should conduct the work/activity analyses and interviews with operating departments as necessary to develop or confirm their input assumptions.

3.8.9 Given the relative size of constructed capital additions in the test year, i.e. about $148 million of distribution assets and $94 million in rental equipment, the Board finds that an allocation of 86% to distribution resulting from the study compared to the historic approximately 60% is questionable. In addition, the change in the storage asset group allocation from 4% to 1% and the fact that estimates of capitalized overhead for NGV stations changed from 27% to 15% between 1998 and 1999 with a similar level of investment, throws the reliability of the study into doubt. The Company provided no satisfactory explanation for these apparent anomalies.

3.8.10 The Board finds that the proposed 1999 allocation to ancillary constructed capital asset groups (rentals and NGV) is too low and rather than substitute an arbitrary allocation will revert to the historic pro rata allocation for the test year. The Board expects that the new methodology will be reviewed and tested during the test year so that there will be greater confidence in, and support for, the result for application in the next rates case.

3.9 COST OF CAPITAL

3.9.1 The Company's test year proposed utility capitalization and cost of capital, as agreed to in the Settlement Proposal, are set out in Appendix C. Although an adjustment mechanism was agreed to in relation to the cost of debt, it was not necessary to invoke it. The cost of common equity used by the Company and by the parties to the Settlement Proposal is the same as that last approved by the Board in E.B.R.O. 495. The derivation of the 1999 allowed cost of common equity is the result of the application of the Board’s *Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities*.

Cost of Common Equity

3.9.2 The Board's Draft Guidelines were introduced for the first time in E.B.R.O. 495. The Guidelines are intended to facilitate the implementation of a formulaic return on equity ("ROE") mechanism. The Guidelines provide for an initial setup phase, to establish a just and reasonable return on equity for each of the Ontario local distribution companies ("LDCs"), given a test year long (30 year) Canada bond forecast. The reasonable return would then be the base against which subsequent adjustments to the ROE could be made. The initial setup phase required that the forecast of the long Canada bond yield for the introductory test year be established, taking an average of three and twelve months forward ten year Canada bond yield forecasts as stated in the most recent publication of Consensus Forecasts, and adding the average of the actual observed spreads between the ten and thirty year Canada bond yields as reported in the *Financial Post* for each business day of a month corresponding to the most recent Consensus Forecasts publication. Then the implied risk premium must be established to account for the utility's risk relative to the long Canada bond yield.

3.9.3 The Guidelines state that the primary methodological approach to be used in evaluating the appropriate risk premium should be the equity risk premium test. Once the initial ROE had been set for each of the utilities through the initial setup phase, a procedure was put in place to automatically adjust the allowed ROE for each utility to account for changes in long Canada bond yield forecasts. The difference between the forecast long Canada bond yields calculated in step one of the initial setup phase, and the corresponding rate for the immediately preceding year would then be multiplied by an adjustment factor, which the Board suggested would be 0.75, to determine the adjustment allowed to ROE. The adjustment factor would then be applied to the utility's previous test year ROE and the sum rounded to two (2) decimal places.

3.9.4 It is the Board's intention that the rate of return formula be reviewed when conditions arise which may call into question its validity. Any adjustment to the utility risk premiums would be done only when there is a clear indication that relative risks have changed. The Guidelines state that the capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.

3.9.5 Evidence before the Board in the E.B.R.O. 495 proceeding led the Board to conclude that, at a long Canada bond yield of 7.25%, a risk premium of 340 basis points was appropriate for the Company.

3.9.6 The Guidelines specify the use of the spreads between the 10 and 30 year Canada bond yields for the month of August 1998, as published in the *Financial Post* which correspond to the selected month in which the *Consensus Forecasts* is published. In the case of Consumers Gas, the Board attempts to issue its Decision before the end of August. Consequently, the analysis of long Canada bond yield spreads must cover a period ending not later than the middle of August. Hence the Board has used a one month period ending August 14, 1998. The allowable rate of return on common equity for the 1999 test year is determined to be 9.51% as shown in the table below. The Board notes that the effective risk premium embodied in this rate of return on common equity is 378 basis points over the forecast long Canada bond yield.

DETERMINATION OF RATE OF RETURN ON EQUITY		
Allowed ROE for Fiscal 1998		10.30%
Fiscal 1999 Long Canada Bond Yield Forecast	5.73%	
Fiscal 1998 Long Canada Bond Yield Forecast	6.79%	
Change in Yield	-1.96%	
Adjustment (0.75 : 1)		-0.7916%
ROE for Fiscal 1999 (rounded to 2 decimal places)		9.51%

3.9.7 The overall cost of capital for the test year is determined to be 8.67%. The supporting calculations are shown in Appendix C.

4 RATE DESIGN

4.0.1 There are three steps involved in allocating costs to the various rate classes: functionalization, classification, allocation.

4.0.2 The process of functionalization groups costs into similar operating functions. Classification groups the functionalized costs into three general groups: commodity, capacity, and customer specific. To provide for rate unbundling, these groups are further sub-classified. The allocation of the classified costs is the process of spreading similarly incurred costs to each rate class on a common factor that can be identified by each class (the allocators).

4.0.3 The revenue requirement to be generated from rates is separated into three components: distribution, gas supply load balancing, and gas supply commodity. The Company carries out the allocation of the deficiency/sufficiency in three stages. First, the allocated gas commodity and pipeline transportation costs are taken from the cost allocation study and used for the development, for each rate class, of the new gas supply and gas supply load balancing unit rates respectively. Second, rate class responsibility for the distribution deficiency/sufficiency is apportioned pro rata on the basis of the allocated rate base. Third, adjustments to this allocation may be made to adjust revenue to cost ratios and to align class rates of return.

4.1 RATE 331 - REVENUE SHARING

4.1.1 Service under Rate 331 is for transportation on the Company's transmission system. Under the existing methodology, the revenues generated are applied as credits to in-franchise customers only. The Company proposed to share the revenues between both in-franchise and ex-franchise customers, based on the manner in which costs for transmission and compression services are borne by each customer group. The Company's rationale for the proposed change is that costs to provide transmission and compression services are borne by all customers pursuant to Rates 325, 300, and 331.

4.1.2 OCAP, being the only party not agreeing to the Company's proposal, agreed to deal with its concerns in argument only. OCAP was opposed to the Company's proposal on the grounds that the revenues generated under Rate 331 are made possible by utilizing assets that were put in place for monopoly customers and that ex-franchise customers are protected from the risks arising from the utilization of these assets through the availability of competitive alternatives.

4.1.3 The Board agrees with the Company's position that the business risk arising from underutilization of these assets falls on the Company's shareholder, not monopoly customers, since the onus is on the Company to demonstrate to the Board that the assets were prudently acquired and that they are used or useful. The Board also notes the Company's argument that the rationale underpinning its proposal is the same as that for the sharing of contract revenues generated from Short Cycle Storage and the premium from Full Cycle Storage. The Board accordingly accepts the Company's proposal.

4.2 GAS SUPPLY MANAGEMENT FEES

4.2.1 Currently, the Company does not identify incremental administrative costs for system supply as it does for direct purchase customers (buy/sell and T-service) who pay a Direct Purchase Administration ("DPA") charge. As a result of the Settlement Proposal and the Board's Decision in E.B.R.O. 495, the Company identified for this proceeding the incremental costs attributed to system gas and proposed to recover them on a volumetric basis through the gas supply commodity charge. To accommodate its proposal, the Company proposed to institute two different gas supply charges in the applicable rate schedules, one for system supply and one for buy/sell supply. The charge applicable to buy/sell includes the recovery of gas commodity and bad debt expense, while the charge for system gas includes, in addition, the recovery of management costs proposed at 17.89 cents per thousand cubic metres. Given the smallness of this fee, no separate identification is proposed of this amount on the bill (about 68 cents a year for a residential customer). The proposed fee is 50% lower than that of Union, the difference being that Consumers Gas recovers the costs associated with commodity-related bad debt expense (approximately 33 cents per thousand cubic metres) through the gas supply charge. On a comparable basis, the fees for the two utilities are approximately the same. Other than OCAP, there was agreement in the Settlement Proposal to accept the Company's proposal. OCAP agreed to confine its opposition to argument.

4.2.2 The DPA charge payable by direct purchase customers consists of a monthly minimum of $50 and a maximum of $815. The Company proposed to increase the maximum charge to $850 to recover an estimated revenue shortfall of approximately $140,000.

4.2.3 Other than OCAP and CENGAS, there was agreement in the Settlement Proposal to accept the Company's proposal. OCAP agreed to confine its opposition to argument. CENGAS withdrew its reservation and offered no opinion on the proposed increase.

4.2.4 Viewing these services as incidental to the Company's distribution operations, OCAP argued that both the system gas fee and the DPA charge should be treated akin to ancillary and non-utility activities and therefore should be determined on the basis of fully allocated costs, not incremental costs. According to OCAP, fees or charges for these services derived on fully allocated costs would help the new competitive natural gas market in Ontario develop efficient administrative mechanisms.

4.2.5 The Board is of the view that, while a restructuring of distribution services may be imminent, there are many operational issues that need to be addressed before gas supply services currently provided by the Company can be considered redundant or ancillary. A number of operational issues are currently being addressed by the Market Design Task Force. The Board prefers to await the completion of the Task

Force's work before such matters proposed by OCAP can be considered. The Board accepts the Company's proposals for the test year.

4.3 ALLOCATION/RECOVERY OF COMPRESSOR FUEL COSTS

4.3.1 Prior to E.B.R.O. 495, the cost of compressor fuel on TCPL was recovered by the Company from system supply customers through the Gas Supply Charge. Customers who elected to directly purchase their own gas requirements (Bundled T-Service) were (and still are) also required to purchase their own compressor fuel requirements from their ABMs and to provide this volume to Consumers Gas. Since the Gas Supply Charge did not apply to Bundled T-Service customers, they were not required and did not pay for system supply compressor fuel.

4.3.2 In E.B.R.O. 495 the Board accepted the recommendation by the Company that compressor fuel costs were more closely related to transmission than to commodity and the recovery of the fuel charge was transferred from the Gas Supply Charge to the Gas Supply Load Balancing Charge. Since there is no separate Gas Supply Load Balancing Charge for general service customers (Rates 1 and 6), system supply compressor fuel charges are captured in the Delivery Charge. Bundled T-Service customers are required to provide their own compressor fuel but are still charged for compressor fuel in the Delivery Charge/Gas Supply Load Balancing Charge. Consequently, these customers receive a credit for an amount equivalent to the compressor fuel charge component in the Delivery Charge/Gas Supply Load Balancing Charge.

4.3.3 Mr. Sheinfield, an employee of Consumersfirst, filed evidence in support of the contention that the current mechanism, despite its sound theoretical foundation, has created problems in the marketplace, particularly for smaller customers in Rates 1 and 6, with the result that proper price signals are impaired, transparency in pricing is difficult to achieve, and customers are confused about their gas supply options. Mr. Sheinfield recommended that the method of allocation/recovery of compressor fuel charges revert to the pre E.B.R.O. 495 method. In the Settlement Proposal, parties except for CENGAS and Union Energy agreed to the proposal by Consumersfirst.

4.3.4 During the hearing, it was noted by Ms. Duguay, the Consumers Gas witness, that the confusion claimed by Mr. Sheinfield for smaller customers may also be explained by the fact that, due to billing system limitations, Consumers Gas is currently unable to credit the fuel charge directly to the individual Rate 1 and rate 6 customers. Instead, The Company pays these credits to the customers' ABMs on the assumption that the ABM will refund or otherwise credit this amount to the customers.

4.3.5 Union Energy and CENGAS opposed Consumersfirst on the grounds that reversion to the old system will create even more customer confusion and would undermine the credibility of the ABM community.

4.3.6 The evidence in E.B.R.O. 495 did not disclose Consumers Gas' inability to flow the credit directly to the customer. The parties' discussion in E.B.R.O. 495 regarding potential confusion was confined to large customers represented by IGUA. There was no discussion of potential confusion for general service customers. Consumers Gas' prefiled evidence in the present proceeding did not disclose problems of customer confusion by any of its customer groups or potential implementation problems.

4.3.7 The Board finds itself in an untenable position. Whether the Company is directed to maintain the current method or revert to the old, concerns about customer confusion may remain or new ones may arise. There are also financial issues that affect ABMs and customers. Further, there are credibility issues that affect the whole industry.

4.3.8 The Board is disappointed by the Company's handling of this issue, both in E.B.R.O. 495 and subsequently. The Board would have thought that a basic analysis of the Company's proposal in E.B.R.O 495 would have considered the ability of the Company's billing system to handle the flow of credit directly to customers. The Board is not aware of any communication by the Company following the E.B.R.O. 495 Decision regarding its discovery that a direct flow was not possible or practical. The Company did not communicate the change to customers after the E.B.R.O. 495 Decision or after the problem was detected. The Board is puzzled as to the reasons the Company's evidence in the current proceeding is silent on this issue.

4.3.9 The Board notes that the Company indicated in this proceeding that when the new billing system is operational it is planning to recover fuel costs only from those customers who do not provide their own fuel, which would appear to eliminate the confusion. The evidence is not clear as to what the practical constraints are, and whether these arose from the delay of CIS and if so, whether they can be addressed in the absence of CIS. In the interest of furthering the workings of the marketplace, however, the Board must make a decision.

4.3.10 The Board directs the Company to revert to the methodology in effect prior to E.B.R.O. 495. The Board notes the position of Union Energy that, should the Board decide in favor of reverting to the old method, Consumers Gas be directed to bear the costs of notifying affected customers of the resulting pricing changes. The Board directs Consumers Gas, in consultation with Union Energy, CENGAS, and Consumersfirst to draft the appropriate notification to customers affected by the change, the reason for the change, and the ABMs role in the current and new arrangement. The notification is to appear on two occasions. The first should form part of or be included with the normal notice following the Board's Decision. The second, a standalone or dedicated notification is to be sent within 30 days from the mailing of the first notice. The content of the notice is to be attached to the Company's Draft Rate Order. The Board appreciates that the ABMs may have to incur costs of their own to adhere to the changed policy. However, the Board has no power in awarding costs beyond costs awards associated with this proceeding.

5 DEFERRAL ACCOUNTS

5.1 "Deferral" accounts capture costs or revenues for which no allowance has been made in the Company's rates. "Variance" accounts capture the variation in costs or revenues from amounts reflected in rates. For ease of reference, the Board may refer to both types of accounts as deferral accounts.

5.2 Simple interest is calculated and recorded based on the monthly opening balances in deferral accounts at the short term interest rate last approved by the Board in the Company's main rates case.

5.3 The rates hearing process examines the accuracy and prudence of the deferral account balances and the appropriate disposition to customers or the shareholders.

5.4 Consistent with previous practice, the Company proposed to clear deferral account balances through a one-time charge or credit in the first billing month (usually October) following the issuance of the Board’s Rate Order.

5.5 Since the actual data for fiscal year-end (September 30) are not available at the time of the hearing or even at the time of issuing the Rate Order, the Company provides upper and lower boundaries on the forecasts for all deferral accounts. For gas supply related accounts, if the actual year end balances fall between the established boundaries, the remaining account balances are carried forward to the subsequent year in the respective accounts. Variances outside the boundaries would be dealt with through an accounting order. Balances remaining in the non-gas supply related accounts are carried forward in the following year's Deferred Rebate Account.

5.6 Based on the Company's latest submission to the Board, dated August 14, 1998, the overall net balance forecast as of September 30, 1998 proposed to be cleared to customers is a $25.3 million credit.

5.7 The Settlement Proposal provides a list of the deferral accounts where agreement was reached on disposition and the accounts that are to apply in the test year. Below are the Board's findings with respect to matters that were issues at the hearing.

Gas Costs

5.8 The balance and disposition of the 1998 Purchase Gas Variance Account was agreed to in the Settlement Proposal, subject to the examination of changes in such balances because of updated gas forecasts. Following examination at the hearing, there were no concerns expressed in respect of the forecast balance and the proposed disposition of the balance. The Board accepts the Company's proposals.

Class Action Suit

5.9 The Class Action Suit Deferral Account records the costs incurred for defending the Company's 5% late payment charge, excluding the amount of any judgement against the Company. Any award of costs made to the Company by the Court will be credited to the account. Only OCAP opposed the Company's proposal to dispose of the balance in this account (forecast at $90,000) on the basis that no decision should be made until the Supreme Court has rendered its decision. The Company argues that these are "period costs" and that the Board has historically allowed the clearing of the balances in the account.

5.10 The Board notes the Company's evidence that the Supreme Court's decision will likely be released by the end of fiscal 1998. If so, any cost award to the Company will operate to offset the balance in the account and the account balance should be cleared. However, if the Court's decision is not released in time for the Company to file its Draft Rate Order, the Board finds that it would be reasonable for the Company to withhold disposition of the balance in this account and the Board so directs. The

Board's decision at this time differs from those in prior years due to the apparent imminence of the Court's final (non-appealable) decision in this regard.

Customer Communications Plan

5.11 The Customer Communication Plan Deferral Account was authorized by the Board on September 11, 1997 (U.A. 111) to apply to the Company's fiscal year post May 15, 1997. The account records the Company's incremental costs to develop, produce and implement the Direct Purchase Communication Plan as a result of the Board's May 1997 Decision dealing with matters pertaining to the utilities' code of conduct. The Company sought to recover $639,238 relating to that campaign. By letter dated March 10, 1998 the Company applied (U.A. 122) to expand the use of the account to include a second customer information campaign driven by increased customer enquiries and media attention regarding direct purchase issues. As the Board had not yet responded to that request, the Company proposed to deal with its request in the E.B.R.O. 497 proceeding. The Company sought the recovery of $494,342 relating to the second campaign.

5.12 During the E.B.R.O. 497 hearing, by letter dated June 12, 1998 the Company applied to further expand the use of the account to include a third customer information campaign. This campaign was recommended by the Board's Market Design Task Force. The Company will share equally with Union a total expected amount of $2.8 million, or $1.4 million each. The Company anticipated that it will spent $100,000 on that third campaign by fiscal year-end and requested that this amount also be included in the disposition of the account's balance. The total balance therefore to be disposed of in fiscal 1998 is approximately $1.233 million. The disposition of the balance is proposed to be as a charge to general service customers served under Rates 1 and 6 on the basis of the number of customers in each rate class.

5.13 There were no concerns expressed regarding the expanded use of the account and the balances recorded. However, there were concerns expressed regarding the clearing of the balance. CAC argued that the Company ought to recover one-half of the amount for the second campaign from the ABMs, since the ABMs caused the confusion necessitating the campaign. The Schools argued that large Rate 6 customers who are typically already on direct purchase should not bear any of the costs.

5.14 The Board accepts that the practices of certain ABMs contributed to the necessity for the Company's campaigns, as in effect argued by CAC. However, CAC has not made any concrete suggestion how the Board can allocate some of these costs to the ABMs and, as the Company points out, neither it nor the Board has the means of compelling the ABMs to contribute.

5.15 With respect to the Schools' concerns of unfair burden, the Board recognizes that there may be an element of imperfect allocation/recovery of such costs. However, given that less than 10% of the balances in the 1998 account will be disposed of to the Rate 6 customer category, the Board does not consider such burden to be undue, especially since there are arguably some benefits derived by all customers through a better informed public. The costs of attempting to differentiate within a rate class category would likely outweigh in this case the benefits of attempting to achieve the ideal sought by the Schools. The Board accepts the Company's proposal.

Municipal Taxes

5.16 Bills 106 and 149 relating to municipal matters received Royal Assent on May 27 and December 8, 1997 respectively. By letter dated December 23, 1997 the Company sought authorization (U.A.119) to record anticipated increases in fiscal 1998 municipal tax expenses arising from the Ontario Government's enactment of Bills 106/149 and from municipal restructuring. By letter dated May 7, 1998 the Board declined such authorization due to lack of evidence attesting to the materiality of cost increases in the 1998 fiscal year. The Board encouraged the Company to re-apply if it becomes aware of material impacts. The Board also noted that it would require, at the time of the re-application, justification for inclusion of any expenses other than those resulting directly from increased levels of taxation and fees. The Settlement Proposal noted that the Company would refile its application. The application, the balances recorded and disposition would be examined at the oral hearing.

5.17 By letter dated May 25, 1998 the Company reapplied for a variance account. The Company's request was now confined to recording the variance of the amounts assessed by the municipalities and the total amount budgeted in fiscal 1998, rather than including consultant, legal and other third party costs as in the original request. The Company estimated the variance in municipal assessments for fiscal 1998 at $4.125 million. The supporting evidence revealed that the $4.125 million forecast is made up of three components. The first, the known component, is an annual amount of $618,000 relating to the elimination of the Business Occupancy Tax which will now be included as part of realty tax bills. The second is an annual amount of $4,378,511 relating to increased municipal taxes calculated using as a base the City of Toronto preliminary tax rates for the pipeline class. The third component is an estimated annual impact of $500,000 for municipal restructuring. The annual total of $5.496 million is multiplied by nine-twelfths to account for the fiscal 1998 portion to yield $4.125 million.

5.18 With respect to fiscal 1999, the Company revised its revenue requirement evidence to include an amount of $5.9 million for additional municipal taxes and fees. The Company also proposed to continue the variance account for fiscal 1999.

5.19 As IGUA and the Schools pointed out, changes in municipal taxes have not historically prompted requests for variance accounts. The Company did not seek such a deferral account in E.B.R.O. 495 but did so well into the fiscal year. The Company concedes that, although it would have been ideal to have applied at that time, “it was premature to do so because the Company did not have sufficient information to assess the extent, the magnitude or the timing of the impact”. But that is precisely the purpose of requesting a deferral/variance account as a mechanism in setting <u>forward</u> rates.

5.20 The Board recognizes that the Company may have believed the criteria for establishing deferral/variance accounts in-year do not differ from those criteria applied in rates cases. The Board will allow the Company to recover the fiscal 1998 variance in municipal taxes at this time, but comments below on how these criteria may differ.

5.21 Turning to the specific forecast balance for 1998, the Company’s variance forecast of $4.125 million uses as a point of reference the Board-approved 1998 budget for municipal taxes of $28.6 million. The evidence is that the 1998 estimate prior to the variance forecast is $28.1, about $0.5 million less. The point of reference shall be the lower amount. The Company's original broad request has been narrowed to capture only changes in municipal assessments. The Company's annualized forecast of $5.496 million includes an amount of $0.5 million for the impact of municipal restructuring. The Board shares OCAP's concerns that the specific causes of any variance may be difficult to determine. The account is to be renamed the Municipal Tax Variance Account as in effect suggested by IGUA and agreed to by the Company, which may alleviate OCAP's concerns. In any event, the account shall exclude any expenses beyond those directly incurred for municipal taxes as assessed by the municipalities. The Board directs the Company to submit detailed support with the Draft Rate Order so that the Board can ascertain the reasonableness of the balance in the 1998 Municipal Tax Variance Account to be disposed of to customers.

5.22 The Board authorizes the Company to continue the Municipal Tax Variance Account for the 1999 fiscal year with the reference point being an amount of $35.0 million which represents the expenses from municipal assessments reflected in the Company's updated filing.

Y2K and Legacy Expenditures

5.23 As a result of the Board's findings in Chapter 3, the Board authorizes the Company to establish for both the 1998 and 1999 fiscal years a variance account for O&M expenses related to Y2K. The balance in the 1998 account shall be brought forward as the opening balance in the 1999 account. Any amount in the 1999 account to be brought forward for disposition in the future shall be the sum of the amount carried over from 1998 and an amount recorded during 1999 over the $6.2 million amount allowed by the Board in rates for fiscal 1999. The Board also authorizes, as a consequence of its findings in Chapter 3, the establishment of a deferral account for 1999 expenses relating to the Legacy systems upgrade. On disposition, the appropriate level of costs to be attributed for the non-utility and ancillary activities will be at issue.

Criteria for Establishing Deferral Accounts

5.24 The Board recognizes that the establishment of ongoing or special (usually short duration) deferral/variance accounts facilitate the use of a future test year in setting utility rates. Such accounts are normally authorized by the Board in advance of the commencement of the test year, usually as part of the main rates case dealing with the test year in question. The Board also recognizes that special circumstances may arise from time to time that may warrant the request for establishing deferral/variance accounts in-year, after rates have been set.

5.25 The Board does not quarrel with the criteria enumerated by the Company to seek deferral/variance accounts. However, it appears that the Company applies the same criteria regardless whether the request is made as part of its rates review or after that review. In the first instance, the considerations normally include the forecastability of the cost or revenue of the item in question, the materiality of significant variations or the need to induce economic behavior.

5.26 In the second instance however, criteria should also include considerations of what is in effect, as argued by IGUA and the Schools, retroactive ratemaking and, as IGUA suggests, of the Company's overall in-year financial performance. Generally, in-year requests for deferral/variance accounts are for cost pressures, real or perceived. Seldom does the utility initiate accounting orders to capture excess revenue items. This selectivity issue or asymmetric approach is of concern to the Board. In-year deferral/variance account requests undermine the business risk assumed by the utility, whether they arise from market considerations or from normal forecasting errors, which risk is reflected in the allowance for a rate of return on common equity. It is also pertinent in the Board's view to weigh the fact that unanticipated expenses can be offset, in whole or in part, through realignment of expenditures. In the absence of these additional considerations, the deferral/variance account process is unfairly tipped against the ratepayer.

5.27 Since in-year requests may not allow proper examination of the Company's financial position, the Company should note that financial performance considerations will be a factor at the time of disposition of balances for accounts authorized in-year.

5.28 The Board recognizes the criteria for establishing deferral/variance accounts and for their disposition may need to be reviewed upon implementation of performance/incentive-based ratemaking.

6 COST AWARDS AND COMPLETION OF THE PROCEEDINGS

6.1 COST AWARDS

6.1.1 Section 28 of the *Ontario Energy Board Act* authorizes the Board, at its discretion, to fix or tax the costs of, and incidental to, any proceeding before it. The Board addresses the awarding of costs in its *Rules of Practice and Procedure* and *Cost Eligibility Guidelines*.

6.1.2 The following parties applied for an award of costs: the Alliance, CAC, CAESCO, CEED, CENGAS, GEC, Energy Probe, HVAC, IGUA, OAPPA, OCAP, Pollution Probe and the Schools.

6.1.3 Total costs claimed by the intervenors were approximately $0.7 million. The Company's forecast of intervenor costs included an allowance of $0.8 million.

6.1.4 Correspondence relating to cost awards was received by the Board as recently as August 28, 1998. In order to expedite the issuance of the Board's Decision regarding 1999 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.

6.2 COMPLETION OF THE PROCEEDINGS

General Matters

6.2.1 The comments below are directed towards the Company and are intended to assist the Board and the participants in future proceedings.

6.2.2 The Company's practice of organizing its pre-filed written evidence by witness, rather than by topic, appears cumbersome and not conducive to a thorough understanding of the whole evidence on a particular topic or issue. The Board suggests that the Company consult with Board Staff to review the organization of its written evidence.

6.2.3 The focus of this Decision is the setting of appropriate rates for the Company's 1999 fiscal year. The Board notes that a number of results from this Decision which impact the Company's ancillary programs and the O&M may require further consideration in Phase II of this proceeding.

Revenue Requirement and Draft Rate Order

6.2.4 The rates currently in effect are those approved by the Board in its E.B.R.O. 495-01 Order. Based on these rates, the Board finds an overall revenue deficiency of $90.4 million, as shown in Appendix D [Determination of Revenue Excess/(Deficiency)] and supported by Appendix A [Rate Base], Appendix B [Utility Income], and Appendix C [Capitalization/Cost of Capital].

6.2.5 Of the $134.2 million revenue deficiency claimed by the Company, approximately $31 million related to delivery or distribution; the balance relates to gas supply (gas supply commodity and load balancing). The Settlement Proposal reduced the revenue deficiency in the delivery component to approximately $29 million. The additional reduction in revenue deficiency of $40.4 million found by the Board in this Decision is entirely related to delivery; there is therefore a forecast 1999 revenue sufficiency in the delivery component of the Company's rates of approximately $12 million.

6.2.6 The Company is directed to adjust its rates as a result of the Board's adjusted revenue requirement and other findings herein so that the revenue-to-cost ratios are not materially different from those proposed.

6.2.7 The Board directs that the new rates be effective October 1, 1998. The Board expects the Company to implement the new rates on the same date.

6.2.8 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 to be accompanied by the following:

i) proposed final rate schedules with appropriate supporting documentation, incorporating the Board's findings;
ii) updated deferral account balances and interest calculations;
iii) draft accounting orders and entries for the new and continuing Board-authorized deferral accounts, along with accounting entries for interest;
iv) a summary of the Board's directives found in this Decision pertaining to future rate filings;

v) drafts of the proposed notices to customers which shall accompany the first customer bill following the implementation date of the new rates; and

vi) other material as directed in this Decision.

DATED AT Toronto August 31, 1998.

H. G. Morrison
Presiding Member

P. Vlahos
Member

R. M. R. Higgin
Member