Ontario Energy Board

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT

AND

IN THE MATTER OF
AN APPLICATION BY

THE CONSUMERS' GAS COMPANY LTD.

FOR RATES

E.B.R.O. 465

DECISION WITH REASONS

E.B.R.O. 465

IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. to the Ontario Energy Board, under Section 19 of the said Act for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution and transmission of gas for its fiscal year commencing October 1, 1990.

BEFORE: C.A. Wolf Jr.
Presiding Member

S.J. Wychowanec, Q.C.
Chairman

DECISION WITH REASONS

March 1, 1991

ISBN 0-7729-8259-7

TABLE OF CONTENTS

1. INTRODUCTION 1
   - 1.1 THE COMPANY 1
   - 1.2 THE APPLICATIONS 2
   - 1.3 THE HEARING 3

2. ECONOMIC AND COMPETITIVE ENVIRONMENT 9
   - 2.1 ECONOMIC ENVIRONMENT 9
   - 2.2 COMPETITIVE ENVIRONMENT 10

3. ONTARIO UTILITY INCOME 13
   - 3.1 GAS SALES AND TRANSPORTATION FORECAST 13
   - 3.2 LATE PAYMENT AND NON-CONFORMANCE PENALTIES FORECAST 19
   - 3.3 REGULATORY TREATMENT OF LAND SALES 20
   - 3.4 ANCILLARY ACTIVITIES 22
   - 3.5 NATURAL GAS VEHICLES ("NGV") 27
   - 3.6 GAS COSTS 30
   - 3.7 OPERATIONS AND MAINTENANCE EXPENSES 35
   - 3.8 NON-UTILITY COST ELIMINATION 45
   - 3.9 INCOME TAX RATES 48
   - 3.10 BOARD ADJUSTMENTS TO UTILITY INCOME 49

4. ONTARIO UTILITY RATE BASE 51
   - 4.1 PLANT HELD FOR FUTURE USE 51
   - 4.2 GENERAL PLANT 54
   - 4.3 CASH WORKING CAPITAL 58
   - 4.4 BOARD ADJUSTMENTS TO RATE BASE 58

5. CAPITAL STRUCTURE AND COST OF CAPITAL 61
   - 5.1 BOARD FINDINGS OF REVENUE DEFICIENCY 62

6. COST ALLOCATION AND RATE DESIGN 65
   - 6.1 COST ALLOCATION 65
   - 6.2 RATE DESIGN 71

7. DEFERRAL ACCOUNTS 81
   - 7.1 EXISTING DEFERRAL ACCOUNTS 81
   - 7.2 PROPOSED DEFERRAL ACCOUNTS 85

8. TCPL TOLL INCREASE 87

9. COSTS 91

10. IMPLEMENTATION OF THE DECISION 95

APPENDICES:

APPENDIX A ONTARIO UTILITY INCOME

APPENDIX B ONTARIO UTILITY RATE BASE

APPENDIX C CAPITALIZATION AND COST OF CAPITAL

APPENDIX D DETERMINATION OF REVENUE DEFICIENCY

1. INTRODUCTION

1.1 THE COMPANY

1.1.1 The Consumers' Gas Company Ltd. ("Consumers Gas" or "the Company" or "the Applicant") is Ontario's largest natural gas distribution company, serving over one million customers. Within its service territory are some of the most densely populated areas of the province including Metropolitan Toronto, Ottawa, the Niagara Peninsula and Mississauga. The Company also serves sections of western Quebec and northern New York State, through wholly-owned subsidiaries which are not under the jurisdiction of the Ontario Energy Board ("the Board" or "the OEB").

1.1.2 In December 1990 ownership and control of the Company passed from GW-CG Investments Limited, a subsidiary of Olympia and York Developments Limited, to British Gas Holdings (Canada) Limited, a subsidiary of British Gas plc.

1.1.3 In addition, the Company has a 50 percent ownership in Tecumseh Gas Storage Limited ("Tecumseh") which is also regulated by the Board. On January 3, 1991 the Board was advised that Consumers Gas had entered into an agreement with Imperial Oil Limited ("Imperial") to purchase

Imperial's 50 percent shareholding in Tecumseh. This purchase will be the subject of a hearing before the Board.

1.2 THE APPLICATIONS

1.2.1 By Application dated December 1, 1989 ("the Application"), Consumers Gas applied to the Board under Section 19 of the Ontario Energy Board Act ("the Act") for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, and transmission of gas for the Company's 1991 fiscal year which commence on October 1, 1990 and ends on September 30, 1991 (the "1991 test year" or "the test year"). The Board assigned Board File No. E.B.R.O. 465 to the Application.

1.2.2 By Procedural Order No. 1 in E.B.R.O. 465 (Procedural Order No. 3 in E.B.R.O. 464), the Board ordered that the hearing of the cost of capital evidence for the Company's 1990 and 1991 test year be combined under Board File Nos. E.B.R.O. 464 and E.B.R.O. 465 respectively. The Company filed in E.B.R.O. 464 its combined evidence with respect to the cost of capital for both test years and that evidence was probed in the E.B.R.O. 464 hearing.

1.2.3 By Order dated September 24, 1990, the Board declared that the rates of Consumers Gas for the sale, distribution, and transmission of gas were interim effective October 1, 1990 for a period of not more than one year from the date thereof.

1.2.4 On February 14, 1989 the Ontario Housing Corporation ("OHC") applied to the Board pursuant to Section 19 of the Act for an Order or Orders fixing the amount of the discount with respect to the Competitive Market Rate Adjustment ("CMRA") and Volume Related Automatic Discount ("VRAD") to be applied by Consumers Gas for the volumes of gas delivered to OHC during the period November 1, 1986 to February 24,

1988. The Board assigned Board File No. E.B.R.O. 459 to the OHC Application.

1.2.5 By Procedural Order No. 1 in E.B.R.O. 459 (Procedural Order No. 3 in E.B.R.O. 465), the Board ordered that the hearing of the OHC Application be concurrent with the hearing of the E.B.R.O. 465 Application. The Board will deal with the matters raised in the OHC Application in a separate Decision with Reasons to be issued in due course.

1.2.6 The Company's request is for a just and reasonable rate of return of 12.46 percent on a utility rate base of $1,707.6 million, inclusive of a reasonable return on equity of 14 percent on a deemed common equity component of 35 percent. To earn these returns, Consumers Gas is requesting that the Board approve rates which would generate sales and transportation revenues of $1,628.2 million in the 1991 test year. Based on current rates, the Company forecast a revenue deficiency of $35.1 million.

1.2.7 However, having become aware during the hearing of an interim increase allowed by the National Energy Board ("NEB") to the tolls charged by TransCanada PipeLines Limited ("TCPL") effective January 1, 1991, Consumers Gas filed additional evidence requesting permission to recover such additional costs from its customers. The Board deals with this matter separately and distinctly in this Decision but has accounted for the impacts of this toll increase when considering the timing of the rate changes.

1.3 THE HEARING

1.3.1 The hearing of evidence in the E.B.R.O. 465 case commenced on November 20, 1990. The final hearing day for evidence in both E.B.R.O. 465 and E.B.R.O. 459 was January 8, 1991, after a total of twenty-four sitting days. Consumers Gas filed its argument-in-chief on January 9, 1990. The arguments of the Intervenors and Board Staff were filed on January 15 and January 17, 1991, respectively. The Company submitted

its written reply argument on January 25 1991. OHC's reply argument in the E.B.R.O. 459 case was submitted on January 31, 1991.

1.3.2 Copies of all the evidence and exhibits in this proceeding, together with a verbatim transcript of the hearing, are available for public examination at the Board's offices.

1.3.3 While the Board has evaluated all relevant evidence and submissions presented in the hearing, it has chosen in this Decision with Reasons to summarize the evidence and positions of parties only to the extent necessary to clarify specific contentious or decisive issues.

Appearances

1.3.4 The following is a list of appearances in the hearing and their representatives:

Consumers Gas	R.J. Howe B. Miller P. McCallen
Board Staff	R.I. Smith
Industrial Gas Users Association ("IGUA")	B. Carroll
Energy Probe	D. Chapman M. Mattson
Union Gas Limited ("Union Gas")	L. Anderson
North Canadian Marketing Inc. Northridge Petroleum Marketing Inc. ("North Canadian and Northridge")	P. Budd
Alberta Petroleum Marketing Commission ("APMC")	D. Trinneer C. Worthy

OHC	M. Peterson
Certain Universities in the Province Served by the Applicant	H. Arndt
Western Gas Marketing Ltd. ("WGML")	K. Taylor D. McLean B. Bullen
Unigas Corporation	P. Leier
Petro-Canada Inc. ("Petro-Canada")	S. Miller J. McPherson
The Ottawa-Carleton Gas Purchase Consortium ("Ottawa-Carleton Consortium")	J. Brett
Canadian Petroleum Association ("CPA")	D. Holgate
F. & V. Energby Co-operative Inc. ("F & V")	W. Fruehauf

Argument

1.3.5 In addition to the Applicant, argument was filed with the Board by the following parties:

- Board Staff
- IGUA
- Energy Probe
- North Canadian and Northridge
- APMC
- OHC
- WGML
- Petro-Canada
- Ottawa-Carleton Consortium
- CPA
- F & V

Witnesses

1.3.6 The following employees were called by Consumers Gas:

J.L. Aiken	Senior Vice-President and Chief Financial Officer
J.W. Bayko	Vice-President, System Operations and Engineering
L.A.E. Beattie	Director, Financial Reporting
C.S. Clarke	Manager, Cost Analysis and Load Research
J. Fagan	Regional Administrator
J.C. Grant	Manager of Budgets
J.A. Gruenbauer	Manager, Contract Marketing
J.R. Hamilton	Director, Market Administration
M. Hare	Director, Environmental Services
R.J. Huggard	Manager, Industrial Commercial Marketing
B. Katugampola	Manager, Plant Accounting
M.P. Levac	Manager, Regulatory Accounting
N. Loberg	Vice-President of Marketing
R.S. Lougheed	Senior Vice-President of Gas Supply
L.M. Luison	Manager, Economic Studies
A.J. Maclure	Manager, Rate Design and Revenue Forecasting

W.G. Martin	Director, Budgets and Forecasts
A.E. Pappel	Manager, Market Planning
A.J. Pleckaitis	Manager, Residential Marketing
R.G. Riedl	Vice-President, Gas Supply
J.J. Sheinfield	Manager, Gas Supply Administration
L.J. Simpson	Vice-President, Human Resources
D.R. Small	Manager of Gas Costs and Budgets
G.P. Stover	Director, Marketing Sales
S.J.A. Szilard	Director, Technology and Development
W.B. Taylor	Director, Financial and Economic Studies
J.R. Tysall	Treasurer
K.A. Walker	Vice-President, Regulatory Affairs
G.T. Waugh	Vice-President and Comptroller
A.C. Wilson	Manager, Financial Studies
R.C. Wood	Director, System Customer Accounting

1.3.7 Consumers Gas also called the following witnesses:

R.M. Alexander	Senior Adviser of Corporate Finance for GW Utilities Limited and Gulf Canada Resources

P. Barnard	Consultant, Canada Consulting Cresap ("Cresap")
H.J. Vander Veen	Partner, Ernst & Young Utility Group
K.C. McShane	Vice-President and Consultant, Foster Associates Inc.
S.F. Sherwin	President, Foster Associates Inc.

1.3.8 Counsel to Board Staff called the following witnesses:

S. Chown	Executive Vice-President, Industrial Economics, Incorporated
L. de Bever	Vice-President and Chief Economist, Crown Life
B. Friedenberg	President, Brent Friedenberg Associates Limited
M. Shaffer	President, Marvin Shaffer & Associates Limited
W.T. Cannon	Associate Professor of Finance, School of Business, Queen's University

1.3.9 WGML called the following witness:

R.G. Caughey	Vice-President, Domestic Sales, WGML

2. ECONOMIC AND COMPETITIVE ENVIRONMENT

2.1 ECONOMIC ENVIRONMENT

2.1.1 In the preparation of its 1991 test year budget the Company utilized macroeconomic information contained in its long-term Economic Outlook which was prepared in August, 1989. This information was updated in December 1989 and March 1990 and it was subsequently followed by the August 1990 Economic Outlook which was prepared for the purposes of its 1992 budget. The Company testified that the timing of the August 1990 Economic Outlook did not permit its direct use in the preparation of the updated filing in this proceeding but indicated that regular consultations between its Budget and Economic Studies personnel during the summer period ensured that the most timely economic information was employed. The Company also testified that economic information released throughout the fall of 1990 revealed a significantly more pessimistic outlook for both 1990 and 1991.

2.1.2 Board Staff's economic consultant, Dr. de Bever, prepared his forecast in November 1990. He also had a pessimistic view of the economy in the short run but, compared to the Company's expectations, he was somewhat less pessimistic on inflation rates, interest rates and housing starts.

2.1.3 Both Board Staff and IGUA submitted that the Board should prefer Dr. de Bever's economic forecast. Board Staff argued that his forecast was more timely, while IGUA argued that recent trends in interest rates support his projections.

Board Findings

2.1.4 The Board observes that both economic forecasts are directionally pessimistic. The Board further notes that the near-term economy is particularly unsettled due to the current recession and the major uncertainties surrounding the Persian Gulf crisis. On that basis, the Board feels that a more pessimistic outlook is in order.

2.2 COMPETITIVE ENVIRONMENT

2.2.1 The Company claimed that its business risk will be similar to that as experienced in recent years. It indicated that the Persian Gulf war has heightened the volatility in international crude prices, but maintained that these events have not changed the competitive position of natural gas, particularly in its large volume markets.

2.2.2 The Company further maintained that since No. 6 heavy fuel oil is a refinery by-product, it will always be priced to sell. It also pointed out that gas customers with dual fuel capability are already using gas and any increase in the price of oil will not translate to higher gas sales.

2.2.3 With respect to competition from electricity, the Company alleged that competitiveness is not directly linked to price, especially in the industrial market, and that electricity remains a competitive threat in that market.

2.2.4 IGUA challenged the Company's assessment of its competitive risks and argued that the Board ought to find that these will be reduced in the test year.

Board Findings

2.2.5 The Board notes Consumers Gas' testimony that essentially all dual fired customers are already using gas. Consequently, the Board is of the opinion that oil price escalations are likely to have little impact on industrial sales other than to essentially eliminate the risk of reversions back to fuel oil. The Board notes that this, however, is counter-balanced by the risk that the recession may result in production cut-backs or plant closures.

2.2.6 The Board recognizes the emerging consumer psychology that natural gas is the "fuel of choice". This, the Board observes, is evidenced by the surge in residential and commercial conversions to natural gas heating. Again, on the counterpart, the Board agrees that new construction is being restrained by the current recession.

2.2.7 The Board also takes notice of Ontario Hydro's public announcement that it will be less aggressive in its pursuit of weather sensitive and water heating loads. Also, an earlier than forecast recovery from the current recession could increase the Company's business opportunities. The impacts of an early recovery would, however, likely not be substantial in the test year.

2.2.8 On balance, the Board finds that Consumers Gas' business risk is only marginally lower than in its previous fiscal year.

2.2.9 The Board views the Company's financial risks as substantially unchanged in relation to fiscal 1990 and finds that the Company's total risk is only marginally lower than it was judged to be at the time of Consumers Gas' last rates case.

3. ONTARIO UTILITY INCOME

3.0.1 A statement of the Company's forecast Ontario Utility Income for the test year is shown in Appendix A.

3.0.2 Parties to the hearing focused on the following aspects of utility income:

- Gas Sales and Transportation Forecast
- Late Payment and Non-Conformance Penalties Forecast
- Regulatory Treatment of Land Sales
- Ancillary Activities
- Natural Gas Vehicles
- Gas Costs
- Operation and Maintenance Expenses Forecast
- Non-Utility Cost Elimination
- Income Tax Rates

3.1 GAS SALES AND TRANSPORTATION FORECAST

3.1.1 Consumers Gas forecast that it will add 34,585 new customers in fiscal 1991, which is 2,095 fewer than were expected to be added in fiscal 1990. Consumers Gas projected that it will sell 9,690.5 10^6m^3 of gas during the test year to 1,074,731 general service customers and 2,512 large volume customers. In addition, it expects to deliver 427.9 10^6m^3 of gas for 42 transportation service customers. Consumers Gas estimated that, based on

rates in place at the time of the hearing, it will generate gas sales and transportation revenues of $1,593.1 million for the test year.

Sales Forecast

3.1.2 Estimates of the volumes of natural gas to be consumed by general service customers, (Rates 1, 2 and 6), were made utilizing average use trends. The Company submitted that conservation measures, along with higher efficiency furnaces and appliances, continued to influence average use in the general service classes but other factors, such as the decline in the real price of gas compared to that of several years ago, and the addition of gas appliances to existing customers, are expected to reverse the trend in the residential and apartment markets in the test year. The Company anticipated that consumption by commercial and industrial general service average users will continue its downward trend.

3.1.3 The evidence revealed that residential customer additions, due to conversion from oil to gas, were about 30 percent ahead of forecast for the month of October 1990. The evidence also revealed that this trend was initiated in the months of August and September 1990, coincident with the advent of the Persian Gulf crisis. The Company testified that this experience could not be expected to continue beyond January 1991, as customers who had not converted by that time would not consider doing so until the late summer or fall of 1991. The Company also testified that the effects of the recession on new construction were more pronounced than originally expected or reflected in the forecast. The Company held that the decline in new construction would at least counter the increase in conversions.

3.1.4 The Company forecast a decline of 1.6 percent in its throughput to large volume customers in the test year compared to 1990. The major cause for the decline is the loss in 1990 of one of the Applicant's largest customers, Cyanamid Canada Inc., due to a plant closure.

3.1.5 The Company continued to rely on the results of its "grass roots" budgeting process. The evidence revealed that a sales forecast based on econometric modelling was 1.3 percent higher than the "grass roots" forecast.

3.1.6 Board Staff argued that the significant decline in the real price of natural gas and the increasing price advantage over competing fuels will increase average use beyond what the Company had proposed. Board Staff suggested an adjustment of 25 m^3 per residential customer and 400 m^3 per apartment customer. With respect to customer additions, Board Staff dismissed the argument that this would be negated by the down-turn in new construction, and suggested that the Board increase the Company's proposed residential customer base by 3,000 connections.

3.1.7 IGUA submitted that the general service forecast is "probably quite conservative" on the basis that the impact of conservation has run its course, and that customer additions will be higher than the Company predicted because of the influence of the Persian Gulf crisis and the declining interest rates forecast by Dr. de Bever.
IGUA also indicated that the higher sales forecast that resulted from using the econometric model, compared to the results of the "grass roots" budgeting process, constitutes "some evidence" that the Company's proposed sales forecast is conservative.

Board Findings

3.1.8 The Board agrees with the Company's expectation that the rate of gas conversions will be essentially counterbalanced by the slow-down in new housing starts. The Board concurs with the Company's estimate of large volume demand in light of the likely impact of the recession on the manufacturing sector. While the Board is inclined to agree with IGUA's assessment that traditional energy conservation impacts are diminishing,

the Board expects that restrained energy use for environmental reasons will likely begin to take effect. The Board, therefore, accepts as being reasonable the Company's sales volume forecast, subject to the modifications made hereinafter to account for adjustments to the Company's gas heating value projections.

Econometric Model

3.1.9 The Company testified that its econometric model was originally conceived and designed for long-term strategic planning purposes. The Company also testified that, as in the past, it developed its gas sales forecast for the general service customers by relying on the "grass roots" budgeting process, and used its econometric model only to check the reasonableness of the results of the "grass roots" process. The Company agreed that the model, as presently structured, cannot be employed for short-term forecasting purposes in place of the "grass roots" process. However, the Company committed to further refine its econometric model to improve its utility for short-term forecasting, and to make it more compatible with its "grass roots" forecast.

3.1.10 Board Staff took issue with the Company's plan to submit the new model to the Board only after it had been fully tested, claiming that this may take several years. It submitted that the next rates case should provide the initial forum for testing the reasonableness of the new model.

Board Findings

3.1.11 The Board is encouraged by the progress to date in the Company's efforts to integrate its econometric modelling with its "grass roots" sales forecasting approach. While the Board continues to view the "grass roots" forecast as the most reliable prediction of sales volumes, it is anxious to see the Company follow through on its intention to meld further its econometric and "grass roots" forecasting techniques. The Board expects

the Company to display its revised econometric model as soon as it has reasonable confidence in its effectiveness, but not to wait until it is fully proven and tested. The Board will require an up-date on the Company's progress in this regard in Consumers Gas' next main rates case.

Normalization Methodology

3.1.12 For purposes of developing average use trends, the Company normalizes its historical volumes to remove the volume variances due to weather and heat content.

3.1.13 With respect to weather normalization, Board Staff challenged the Company's assumed linear relationship between weather and gas consumption for heating, and submitted that the Board should urge the Company to investigate other techniques for measuring and removing the effects of weather from historical sales volumes.

3.1.14 With respect to normalization for heat content, Board Staff noted that the heat content of the gas entering the Consumers Gas system has been higher in recent years than that entering the TCPL system. Board Staff, therefore, alleged that the Company's methodology for normalizing sales volumes, whereby it uses the heat content of its gas entering the TCPL system, as opposed to the heat content of the gas entering its own system, results in lower volume forecasts. The under-estimation, according to Board Staff, stems from the failure to reflect the "Energy-in Transit" adjustment to the actual heat content of the gas purchased from western Canada. The "Energy-in-Transit" adjustment is a volumetric exchange transaction between Consumers Gas and TCPL for the purpose of equalizing the heat content of the gas entering the system in western Canada with the heat content of the gas delivered to Consumers Gas' system.

3.1.15 Board Staff submitted that, in preparing the sales budget in the future, the Company should base its heat content normalization on the heat content entering its own system. For the test year, Board Staff argued for an upward adjustment of 0.3 percent, or 30 $10^6 m^3$ to the total budgeted volumes. This, it claimed, would reflect the average variance between the heat content used for budgeting, and the actual heat content of the gas which entered the Consumers Gas system in the years 1989 and 1990. According to Board Staff this adjustment would result in a revenue increase of $4.7 million, and a corresponding gas cost increase of $3.5 million in the test year.

Board Findings

3.1.16 For the purposes of this Decision, the Board accepts the Company's weather normalization methodology. The Board directs the Company to further investigate methods to more effectively segregate its weather sensitive and non-weather sensitive loads.

3.1.17 The Board finds the evidence to be convincing that the use of the 37.6 MJ/m^3 standard overstates the heat content of the Company's supplies of gas to its customers. For the purposes of this Decision, the Board accepts the proposal advanced by Board Staff, and accordingly deems an increase of $4.7 million to the Company's test year sales revenue forecast to compensate for the adjudged overstatement in the heat content. However, due to the Board's adjustment to unit gas costs, discussed elsewhere herein, the Board deems an increase in gas costs in the amount of $3.6 million rather than $3.5 million suggested by Board Staff.

3.1.18 The Board requires Consumers Gas to present evidence at its next rates case to confirm the heat content of its system gas, and to include in the analysis the substantiated calorific impacts of "Energy in Transit" adjustments and the quantified effects of its changing mix of suppliers.

3.2 LATE PAYMENT AND NON-CONFORMANCE PENALTIES FORECAST

3.2.1 Included in the Company's Other Operating Revenue forecast are amounts of $6.8 million relating to penalties for late payment, and $100,000 for non-conformance by interruptible customers who do not curtail their consumption of gas when requested.

3.2.2 The $6.8 million relating to late payment results from a revised regression equation wherein the personal debt ratio and prime bank rate were added as explanatory variables.

3.2.3 The $100,000 non-conformance amount represents a decrease of $400,000 from the Company's 1990 estimate. The Company explained that the 1990 level was caused by the unusually cold weather in December 1989; if it were not for the cold weather, the amount would have been about $150,000. The Company attributed the anticipated decrease from $150,000 to $100,000 in the test year to increased customer sophistication.

3.2.4 Board Staff submitted that both the late payment and non-conformance forecasts are understated, but it did not recommend an adjustment. IGUA argued for an increase of $150,000 to $160,000 to the forecast of non-conformance penalties, and $350,000 to the forecast of late payment penalties based on the average levels of penalty revenues generated in the three years prior to the test year.

Board Findings

3.2.5 Having reviewed the evidence, the Board is not persuaded that the expected revenue has been understated, and accepts the Company's forecast of the test year revenues that will flow from late payment and non-conformance penalties.

3.3 REGULATORY TREATMENT OF LAND SALES

3.3.1 As part of its Niagara region reorganization, the Company intends to sell two properties during the 1991 fiscal year. The evidence revealed that the expected profit from the sale of the lands will be $1.9 million.

3.3.2 In its evidence, the Company noted that the regulatory treatment by the Board with regard to the disposition of land profits, has not been consistent over the years. The Company proposed that the profit should accrue to the shareholders on the basis that land, unlike other assets, is non-depreciable for ratemaking purposes and, therefore, it does not return the original investment to the shareholders. The inability to fully recover the original cost represents, according to the Company, a risk to the shareholders and, therefore, they ought to benefit from any gain.

3.3.3 As an alternative, the Company stated that it is prepared to accept that the ratepayers assume the risk from the sale of land, as is the case with other assets, provided the following conditions are fulfilled:

- shareholders are kept whole on the investment in land;
- shareholders are allowed a rate of return on the investment in land until such assets are disposed of; and
- shareholders are allowed to recover all costs of disposal, including any costs of preparing the property for sale.

3.3.4 Further, the Company stated that such regulatory treatment, if applied in this case, should be considered as a precedent for all future rate cases. The Company expressed concern that the $1.9 million profit might go to the account of the customers in this case, but losses in the future might be treated differently by a subsequent Board Panel.

3.3.5 Board Staff argued that, as a matter of principle, the treatment of land should not differ from that accorded to any other utility asset for

ratemaking purposes. Even if the Board did not accept this principle, the profit in this particular circumstance should accrue to the ratepayer, Board Staff argued, because there are ratepayer costs associated with the decision to sell. Board Staff pointed out that the study which quantified the net benefit of $31,000 to the ratepayers, due to the reorganization of the Niagara region, assumed that the profit accrued to the shareholders. Board Staff implied that this is an insignificant amount and it could well turn out to be a net cost. Therefore, Board Staff argued that the ratepayers should receive the land sale profit in order to ensure that the reorganization will be of benefit to them.

3.3.6 IGUA invited the Board to establish a policy which will provide consistent regulatory treatment for the gains or losses realized upon the sale of land. IGUA submitted that the sharing approach adopted by the Board in certain decisions dealing with this issue is a more reasonable approach than would be the all or nothing approach advocated by the Company.

Board Findings

3.3.7 The Board notes the Company's concern over the lack of consistency in prior Board decisions regarding the allocation of the profits from land sales. While the Board hopes that greater consistency will be reflected in future decisions, the Applicant is reminded that the Board must consider each case on a de novo basis, and that the jurisdiction of each Board Panel is limited to the case before it.

3.3.8 In principle, the Board is of the opinion that the allocation of 100 percent of the profit from land sales to either the shareholders or the ratepayers might diminish the recognition of the valid concerns of the excluded party. For example, the timing and intensity of land purchase and sales negotiations could be skewed to favour or disregard the ultimate beneficiary.

3.3.9 The Board concurs with IGUA that a sharing of the profits or losses from land sales is the most equitable approach in this case. The Board also feels that this treatment has the greatest potential for consistent regulation.

3.3.10 The Board, therefore, finds that the $1.9 million expected profit from land sales, as a result of the Company's Niagara region reorganization, shall be allocated equally to the Company's shareholders and ratepayers.

3.4 ANCILLARY ACTIVITIES

3.4.1 The Company operates several programs which are considered complementary to the utility business. These programs are:

- the rental program;
- the merchandise sales program;
- the heating insurance program; and
- the merchandise finance program.

3.4.2 As in past hearings, the Company presented rates of return for these programs on a marginal, or partially allocated, cost basis, maintaining that this is the appropriate way of judging the profitability of these programs.

3.4.3 The evidence presented indicated that, on this basis, the rental program in the test year is forecast to earn a rate of return of 12.17 percent, the merchandise program 22.9 percent, and the merchandise finance program 12.44 percent. The heating insurance program is expected to produce a gross margin of 29.9 percent.

3.4.4 In its E.B.R.O. 452 Decision the Board expressed concern that non-gas appliances accounted for a significant proportion of the sales within the merchandise sales program. The evidence presented in the present case indicated that the proportion of gas appliances increased from 29.9 to 64.2 percent in the fiscal 1986 to fiscal 1990 period. The Company stated that

in the long term it would like to sell only gas appliances but reiterated that selling non-gas appliances for the time being builds customer loyalty and consumer awareness, and enhances the program's profitability.

3.4.5 The heating insurance program was initiated in 1986 and currently insures some 100,000 subscribers against certain parts and labour costs. In its E.B.R.O. 452 Decision the Board stated that the Company should examine whether the annual fee could be supported by actuarial studies. After investigating actuarial studies, the Company concluded that it would not be cost effective to undertake detailed actuarial studies and to run the program on such a basis. The Company proposed instead that the plan can be managed effectively by setting the premium at a level which would ensure that there is a reasonable margin of profitability.

3.4.6 Pursuant to the Board's E.B.R.O. 452 Decision, the merchandise finance program was excluded from consideration in the Company's initial prefiled material for this case. During the hearing the Company requested that the Board include the program in the utility operations. It claimed that this program is an important part of utility operations, and cited the improved measurement and performance of the program in the 1991 test year and beyond. The Company indicated that including the program in utility operations for the test year would reduce the proposed gross revenue deficiency by $0.4 million. The Company's financial data presented in the Appendices include this program in utility operations.

3.4.7 IGUA reiterated that ancillary activities which require a subsidy by the ratepayers should either be excluded from utility operations, or sufficient revenues ought to be imputed to generate a rate of return that is no less than that allowed for the Company's utility operations. To the extent that the merchandise finance program does not require a subsidy, IGUA was not opposed to its inclusion in utility operations for the test year.

3.4.8 F & V argued that none of the ancillary activities should be part of the regulated utility on the basis that they do not involve the distribution, transmission or storage of gas.

3.4.9 Board Staff submitted that, in view of the role these programs may play in the pursuit of energy conservation or energy efficiency under some form of integrated resource planning, these programs, including the merchandise finance program, should not be removed from utility operations. However, Board Staff argued that, for these programs to operate efficiently, the Board ought to impute revenues in the event the programs do not earn the Board allowed rate of return on a fully allocated cost basis.

3.4.10 On a fully allocated cost basis, and on its 11.97 percent overall rate of return recommendation, Board Staff calculated that the Board should impute revenues of $412,000 for the rental program, $444,000 for the merchandise sales program, and $108,000 for the merchandise finance program. However, Board Staff acknowledged an error in its calculation of short-term debt which would reduce these amounts somewhat.

3.4.11 Board Staff further submitted that, with respect to the rental program, the Board should direct the Company to investigate and propose, at its next main rates case, how "miscellaneous service overheads" can be better allocated among the categories of rental work, heating equipment work, and customer-owned non-heating equipment work. Board Staff also suggested several ways in which the Company could make changes to improve the financial performance of its merchandise sales program. With respect to the merchandise finance program, Board Staff pointed out that, while the authorized dealer portion of the payment deferral program has been removed from the finance program analysis, it was not added to the sales program analysis, and that the Company should address this item in its next main rates case.

Board Findings

3.4.12 The Board finds that no new compelling evidence has been presented in this case to warrant reversing its E.B.R.O. 452 Decision, wherein it was found that ancillary programs should be marginally costed.

3.4.13 The Board notes that both the Company and Board Staff have in their arguments incorporated concerns relating to the upcoming Integrated Resource Planning ("IRP") hearing. The Board agrees that, once implemented, an effective IRP program will likely impact on the Company's ancillary programs. However, it is not likely that an IRP program will be defined and put in place in time to impact during the test year. The Board finds that it is premature to attempt now to tailor ancillary programs to meet IRP needs.

3.4.14 With regard to the rental program, the Board does not accept the Company's claim that rental rates continue to be dictated by competition from Ontario Hydro. The Board directs Consumers Gas, at its next rates case, to present evidence to establish the degree of competition it is facing from Ontario Hydro.

3.4.15 The Board notes the strides that Consumers Gas has achieved in its efforts to increase the proportion of gas appliance sales in its merchandise sales program. The Board encourages Consumers Gas to continue to emphasize gas appliances and, while the Board endorses the Company's long-term objective to sell only gas appliances, it appreciates the synergistic benefits of also offering non-gas appliances in today's market.

3.4.16 The Board finds no compelling reason to reverse its decision in E.B.R.O. 452 and, therefore, continues to hold that the merchandise financing program shall be excluded from the Company's utility operations. The Board is of the opinion that, regardless of the revenues generated by this activity, it is by its nature, too far afield to be appropriately included in

utility operations. The impacts on Utility Income and Utility Rate Base due to this exclusion are footnoted in Appendices A and B.

3.4.17 The Board accepts the results of the Company's analyses which indicated that it would be unreasonable to undertake detailed actuarial studies to test its heating insurance program. The Board endorses the setting of premiums at levels which generate rates of return at or above the overall rate of return authorized for utility operations. While the Board considers a 29.9 percent gross margin for this program to be higher than would be expected, it is content to allow the marketplace to set the upper limits for premiums.

3.4.18 The Board observes that advertising to promote natural gas use and gas appliances, other than by the use of "bill stuffers", reaches beyond the Company's franchise areas. The Board, therefore, finds it difficult to understand why such generic advertising is not coordinated to a greater extent, and cost-shared among the provinces' major gas utilities. The Board expects Consumers Gas to minimize its advertising costs by making greater use of cost-shared generic advertising, and report on its progress at its next rates case.

3.4.19 The Board considers ancillary programs as supporting the Company's gas distribution activities and to be beneficial to both the Company and its customers. The Board, therefore, rejects F & V's proposal that these programs should be summarily removed. With the exception of the proposals regarding the merchandise financing program, the Board accepts the Company's submissions regarding its ancillary programs and the rates of return which they are forecast to generate.

3.5 NATURAL GAS VEHICLES ("NGV")

3.5.1 In its E.B.R.O. 452 Decision the Board expressed concern about the NGV program's economics and the Company's marketing strategy. The Board directed the Company to develop a new marketing plan using external assistance and to provide, at the next main rates case, an updated break-even analysis.

3.5.2 With the assistance of Woods Gordon, the Company developed a new marketing plan and a break-even analysis. The marketing plan includes a number of strategies to overcome the current hurdles in marketing natural gas as a transportation fuel, and it also focuses on minimizing investment and on controlling costs. The break-even analysis indicated that revenue shortfalls will persist for another five to six years.

3.5.3 The evidence indicated that the revenue shortfall in the 1991 fiscal year will be $2.5 million while the cumulative shortfall since its inception in 1983 is over $10 million. The total revenue shortfall to 1995 is expected to exceed $17 million.

3.5.4 The Company reiterated the program's potential societal benefits and said that development of alternative transportation fuels is a matter of public policy with both the Ontario and Federal governments. The Company indicated that financial support for the program by both levels of government continues, and that there has been an enhanced interest in the program by governments, by the automobile manufacturing industry and by the public. The Company also noted that NGV will be a subject of discussion at a planned hearing on integrated resource planning.

3.5.5 Both IGUA and Board Staff challenged the Company's new marketing plan and its break-even analysis. They submitted that the Company's evidence on profitability is unconvincing or optimistic.

3.5.6 IGUA argued that there is no credible basis upon which the Board can continue to require ratepayers to subsidize this program. It urged the Board to eliminate the $2.5 million revenue shortfall in the test year and pointed out that, if further subsidies for the program are to be made available, these should come from government since the eventual benefits will be to society as a whole.

3.5.7 Board Staff submitted that the ratepayers will continue to bear a substantial risk associated with the program and that it is necessary to apportion some risk to the shareholders. Board Staff proposed that, beginning with the 1991 test year, a portion of the shortfall should be placed in a deferral account. When NGV becomes profitable, Board Staff argued, the Company could propose that the shareholders be allowed to recover the revenue shortfall they had borne through their NGV profits. Board Staff pointed out that this proposal is superior, from a Company incentive point of view, to that of simply disallowing a portion of the revenue shortfall.

Board Findings

3.5.8 The Board notes Consumers Gas' acknowledgement that current activities in the United States have the promise of generating North American acceptance of natural gas vehicles and, should that occur, it is likely that a competitive private sector will emerge and seek to provide vehicle conversions and service/fuelling station outlets. The Board, therefore, believes that it is important that the infrastructure that the Company has established be preserved in order to take advantage of this broader acceptance, if or when it occurs.

3.5.9 On the other hand, it is by no means certain whether Consumers Gas' role in the future NGV marketplace will extend beyond its traditional function of distributing gas. This, coupled with the continuing need for ratepayer subsidization of the Company's NGV program, exacerbates the concern as

to how, if ever, the ratepayers will recover their investment in this program.

3.5.10 The Board recognizes that there is a third, very important, aspect of the Company's NGV program, i.e. its ability to make significant contributions to the alleviation of environmental problems. The Board notes, however, that the program's potential environmental benefits are not specific to Consumers Gas' ratepayers alone, but are to the benefit of society as a whole.

3.5.11 Given the complexity of the NGV program, and the current uncertain environment in which it exists, the Board concurs with the Company's assessment that the program should be restrained until current uncertainties are resolved, and market projections and the role of the utility are clarified.

3.5.12 The Board requires Consumers Gas to protect against the erosion of its current infrastructure but to restrict its aggressive NGV marketing efforts to only the conversion of fleet vehicles. The Board expects Consumers Gas to actively solicit additional government support in recognition of the societal benefits that the program offers.

3.5.13 While the Board considers that the Company can likely pursue the above objectives at costs below those it now proposes, the Board accepts these costs for the test year. However, the Board directs Consumers Gas to submit a budget for its next main rates hearing which will reflect the further maximum reasonable cost reductions to the ratepayers that can result from program restraints, alternate funding and further coordination with involved participants both in Ontario and abroad. The Company might also investigate ways to restructure this business with an aim toward reducing ratepayer subsidies.

3.6 GAS COSTS

3.6.1 The Company's proposed $1,150.1 million for gas costs in the test year excludes the TCPL interim toll increase of January 1, 1991, and includes the costs associated with: gas purchases from several suppliers; Union Gas' storage and transportation rates approved in E.B.R.O. 462; Tecumseh's rates as proposed in its E.B.R.O. 466 filing; and TCPL's January 1, 1990 tolls.

3.6.2 The Board has determined that it needs to make specific findings with respect to the following issues:

- 1991 Gas Supply Costs and the Gas Portfolio
- FS-WACOG

1991 Gas Supply Costs and the Gas Portfolio

3.6.3 The 1988 Gas Sales Contract between Consumers Gas and WGML specified, among other things, a Block A and Block B price of $2.20 per gigajoule for the period November 1, 1988 to October 31, 1990. By an Amending Agreement dated September 5, 1990 the parties renegotiated a price of $2.02 per gigajoule for the contract year beginning November 1, 1990. The evidence revealed that the only other changes to the 1988 Gas Sales Contract were of an administrative nature, i.e. the references to Block B gas and fuel gas were eliminated since both are no longer provided by WGML. The Company requested that the gas costs flowing from the Amending Agreement be accepted for ratemaking purposes on the basis that the $2.02 price is prudent and reasonable.

3.6.4 Regarding the negotiating process, the Company testified that the redetermined price was linked by agreement to the outcome of the arbitration proceeding between WGML and Union Gas. The outcome of

that arbitration process was a price to Union Gas of $2.04 per gigajoule. The evidence also revealed that ICG Utilities (Ontario) Ltd, now Centra Gas, Ontario Inc. ("Centra Gas") renegotiated a price for its WGML gas supply which was determined for one year terms at $2.10, $2.20, and $2.30 per gigajoule for the first, second, and third contract years, respectively.

3.6.5 Messrs. Friedenberg and Shaffer, on behalf of Board Staff, were called upon to submit evidence and testify on the reasonableness of the Company's negotiated price. Having examined the proposed price under various criteria, they concluded that $2.02 per gigajoule was within the range of reasonableness, albeit at the high end of the range.

3.6.6 Certain parties in the proceeding argued in support of, and no party argued against the acceptance of Consumers Gas' redetermined price of $2.02.

3.6.7 Board Staff pointed out that short-term gas supplies, 95 percent of which are sourced through buy/sell arrangements, represent 52 percent of the Applicant's total gas supply. Referring to the evidence of Messrs. Friedenberg and Shaffer, that the Applicant could reduce its overall gas costs in the short term by contracting more short-term firm gas, Board Staff argued that the state of the gas supply market now, and in the near future, should cause the Company to consider changing its supply mix.

Board Findings

3.6.8 Based on the evidence presented, and the conditions that prevailed at the time of the renegotiation, the Board concludes that the purchase prices for the Company's test year gas supplies from WGML and other suppliers were negotiated and otherwise arrived at in a prudent manner, with due regard for the needs of the ratepayer.

3.6.9 The Board notes that there was general agreement that the price that resulted from the Company's negotiations with WGML is "within the range of reasonableness".

3.6.10 For the purposes of this hearing, and in consideration of current circumstances, the Board accepts the cost consequences of the Company's gas purchase arrangements for the test year as having been prudently incurred.

3.6.11 The Board finds that there is no convincing evidence that Consumers Gas' portfolio approach, whereby short and long-term supplies are combined, is inappropriate, or that the Board should encourage the Company to seize short-term pricing opportunities, at the expense of longer-term security of supply assurances, as proposed by Board Staff.

FS-WACOG

3.6.12 For ratemaking purposes, the Board allows, as a cost of service, the Company's gas costs under its various buy/sell arrangements. In the past, the reference price, FS-WACOG, was determined by a methodology approved by the Board in E.B.R.O. 452-3.

3.6.13 Consumers Gas proposed to modify the methodology for determining the reference price in two ways. First, only firm gas and firm transportation services with terms equal to one year or greater would enter into the calculation of FS-WACOG. This proposed methodology would exclude from the calculation of FS-WACOG any seasonal, peak day, or discretionary spot gas supply or transportation services which, unlike buy/sell arrangements, do not provide for firm daily deliveries under terms of one year or greater. This proposal would reduce FS-WACOG by $1.443 per 10^3m^3 for the test year.

3.6.14 Second, the current methodology that is used to produce the FST adjustment which is applied to "deem" a conversion of FST service to FS service would be replaced by a proposed method which adds to purchased WACOG an amount that is derived by applying the toll differential between FS and FST service to deliveries of FST volumes. This proposed methodology would further reduce FS-WACOG by $2.055 per 10^3m^3 for the test year.

3.6.15 The combined impact of those changes would be to reduce the cost of gas to operations in the test year by about $11.3 million, and result in reduced profit margins for buy/sell customers.

3.6.16 All parties commenting on this issue urged the Board not to accept these changes. Below are some of the reasons stated in support of their positions:

- The parity that now exists between the buy/sell and transportation service option would be disturbed.

- The proposal is inconsistent with the rationale of the Board's previous decisions which accepted the current method.

- The criteria for exclusion are arbitrary and internally inconsistent.

- No consultation with industry took place, and no advance notice was given of the Company's proposal.

- Excluding the higher cost gas supplies in the calculation of FS-WACOG, while including these costs when billing a buy/sell customer, would be unfair.

3.6.17 It was suggested by North Canadian and Northridge that, should the Board decide that the current methodology needs to be modified, the change

should be delayed or phased-in to accommodate an orderly implementation or transition by the parties affected.

3.6.18 While not directly related to the specific issue at hand, IGUA proposed, in argument, that the Board could describe a nominal "buy" price of perhaps $1 and then prescribe a buy/sell sales rate for each rate class containing a gas supply charge in an amount equivalent to the nominal price. This approach, IGUA argued, would significantly reduce the Company's cost of service by reducing the tax implications when acquiring gas under buy/sell arrangements and the associated working capital requirements.

Board Findings

3.6.19 The Board concurs with the Applicant's assessment that its current FS-WACOG price calculation methodology is in need of change to exclude the growing impacts of seasonal, peak day and discretionary spot gas supplies, and to correct for the toll differential between FS and FST deliveries. However, the Board shares the concerns expressed by IGUA, the Ottawa-Carlton Consortium and others that the proposed change had not been effectively publicized and would, if implemented now, cause significant hardships to existing buy/sell customers.

3.6.20 In line with the argument by North Canadian and Northridge, it appears to the Board that, were the proposed changes to be implemented at this time, it would be necessary to "grandfather" existing buy/sell customers, at least until such time as their current supply contracts expire or are renewed. However, there is no evidence before the Board at this time to describe how such grandfathering could be implemented, or how it would affect the Company's test year rates and revenues.

3.6.21 For the purposes of this test year the Board rejects the Applicant's proposal to change its FS-WACOG calculation methodology to exclude

seasonal, peak day or discretionary spot gas supplies, or to revise the method of converting FST to FS service.

3.6.22 The Board directs Consumers Gas to again bring these matters forward at its next main rates case. The Board further directs Consumers Gas to alert all current and new buy/sell customers that these methodology changes will again be considered at its next main rates case hearing, and that, should grandfathering be considered at that time, buy/sell customers who have entered into new or renewed supply contracts subsequent to the date of this Decision cannot be assured that they will be exempted from any new FS-WACOG price that may result. The Company is further directed to include, in its next rates case filing, an analysis of the impacts that would result from grandfathering various categories of buy/sell customers.

3.6.23 For the purposes of determining the revenue requirement for the test year, the Board, therefore, accepts that FS-WACOG shall be $110.877 per 10^3m^3, and that the Company's gas costs shall increase by $11.3 million.

3.6.24 The Board notes IGUA's alternative proposal of a nominal "buy" price for buy/sell gas in an effort to reduce GST exposure. This proposal has not been tested to determine its legal and practical limitations. As there may be some merit in the proposal, the Board encourages the parties to raise this issue for full consideration at Consumers Gas' next main rates case.

3.7 Operations and Maintenance Expenses

3.7.1 Consumers Gas forecast its Operations and Maintenance ("O&M") expense for the 1991 test year to be $184.6 million, which is $16.8 million or 10.0 percent higher than its fiscal 1990 estimated O&M costs. The largest component of this increase was salary and wage related which, together with associated employee benefits, amounted to $12.2 million.

3.7.2 The following O&M aspects were issues at the hearing:

- Labour Productivity
- Compensation Costs
- Regulatory Expenses
- Arbitration Expenses
- Sales and Marketing Expenses

Labour Productivity

3.7.3 In its E.B.R.O. 452 Decision, dealing with the 1989 fiscal year, the Board expressed concern about the decline in the Company's labour productivity gains and directed it to submit evidence to answer whether labour efficiency/productivity has improved, whether it has improved to the extent possible, or whether management can achieve greater productivity gains. In its E.B.R.O 464 Decision the Board also expressed concern about the large increases in staff that have occurred since 1987.

3.7.4 In response to the E.B.R.O. 452 directive, Consumers Gas established a task force and retained Cresap to provide its expertise in this project. The Cresap report was part of the evidence in this hearing.

3.7.5 Cresap's terms of reference called for an audit and opinion of both the Company's corporate approach to productivity, and the measures currently used by the Company to improve productivity. While the Cresap report was positive in its overall assessment of the productivity culture within Consumers Gas, it identified eleven areas where the Company might enhance productivity.

3.7.6 The Company accepted the Cresap report and initiated a program to respond to the report's recommendations. Specifically, of the eleven opportunities cited in the report, five were prioritized by senior

management for action and, according to Company testimony, action plans for implementation would be defined in the spring of 1991.

3.7.7 Upon completion of the report, the Company asked Cresap to review the activities of five departments most affected by deregulation. The result of this review was an Executive Summary submitted to the Company which called for certain organizational changes. The Company testified that this second report's recommendations were expected to be implemented "within six months".

3.7.8 The Company also described its internally-initiated performance effectiveness reviews as well as an ongoing study by Nolan Norton Canada relating to information technology needs.

3.7.9 Board Staff submitted that the Company failed to explain satisfactorily why the plateauing of cost per customer improvements is unavoidable, and that it failed to provide any productivity measurements, other than cost per customer, to indicate improvement. Board Staff argued that the contents of the Cresap report and the Company's reaction to it provide no indication of serious effort by the Company to increase productivity. Arguing that neither the Cresap report nor the Company provided an analysis of productivity measures, Board Staff urged the Board to direct the Company to retain a consultant to produce a productivity report which would include appropriate measures of productivity, and an explanation for the recent decline in productivity gains.

3.7.10 For the test year, Board Staff argued that the Board ought to reduce, for ratemaking purposes, the Company's O & M expenses in order to provide the required pressure to improve productivity. Board Staff proposed that the Board should deem a productivity gain of 3.38 percent in the test year, since such a rate would reflect a productivity gain in the two year period, 1991 over 1989, which would equal that which was obtained in the period 1989 over 1988.

3.7.11 IGUA questioned whether the evidence supports the Company's inference that labour efficiency and productivity have improved significantly over the years since 1988. IGUA pointed out that the 173,000 customers and 398 employees added in the period 1988 to 1991, including 36,000 customers and 67 employees forecast in the 1991 test year, is disproportionate to the 127,000 customers and 24 employees added in the 1984 to 1987 period.

Board Findings

3.7.12 The Board concludes that Consumers Gas has not effectively replied to the questions that were put forward in the Board's E.B.R.O. 452 Decision. The Company's exclusion of the matter of productivity measurement from the terms of reference for the Cresap report is seen as a lethal flaw. The Board reminds the Company of the adage that an organization responds to what management inspects, not necessarily to what management expects. The absence of quantifiable measures of performance will essentially eliminate management's ability to inspect and accordingly to reward (or chastise) performance.

3.7.13 The questions posed by the Board in its E.B.R.O. 452 Decision were not directed to ascertain if Consumers Gas is conscious of the need for productivity improvement, but rather how much is being done, and how well is it being done. In the Board's opinion the Cresap report provides little confidence that the answers to these questions would have put the Company in a favourable light.

3.7.14 The most positive aspect of the Cresap report, and the testimony of Consumers Gas' witnesses, was that eleven areas warranting attention were identified and prioritized to focus on five primary opportunities for productivity improvement. However, the pace at which these five priority opportunities have been pursued is seen to be woefully slow. The Board finds it unconscionable that, given the elapsed time, action plans to address

these opportunities had not been defined, approved and initiated prior to this hearing. The Board sees this as lamentable evidence of the lack of a sense of urgency or serious dedication on the part of the Company.

3.7.15 The Board expects Consumers Gas to correct this impression, and to come forward at its next rates hearing with hard evidence that what is now seen to be a rather cavalier attitude has been replaced with an active and effective program to implement, measure and reward productivity improvements, and that this program pervades all employee levels within the organization.

3.7.16 The Board finds that Consumers Gas has not effectively responded to the questions that were put forward, and has not demonstrated that it is "paying close attention to cost reduction and productivity gains" as required by the Board's E.B.R.O. 452 Decision. The Board, therefore, accepts Board Staff's recommendation that it is proper to impute a productivity gain equal to that which was obtained in the 1988 to 1989 period.

3.7.17 The Board, therefore, imputes a productivity gain of 3.38 percent, and consequently finds a cost reduction of $2.3 million in the Company's budgeted salaries and wages as being appropriate for the test year.

Compensation Costs

3.7.18 Of the proposed $184.6 million in the O&M budget for the test year, $121.8 million is related to labour and, of this amount, $28.3 million is related to employee benefits. These levels of expenditure reflect an average salary increase of 6.3 percent and an employee average benefits increase of 7.7 percent over those in fiscal 1990.

3.7.19 Board Staff argued for a $0.5 million reduction to the proposed level of employee benefits on the basis that the proposed rate of increase is excessive.

Board Findings

3.7.20 The Board has considered the Company's proposals against the current rates of increase in the cost of living, the recessionary climate and the Board's expectation in its E.B.R.O. 464 Decision that cost reductions would be forthcoming. The Board concurs with Board Staff that a reduction is in order.

3.7.21 The Board, after considering all the evidence, deems appropriate a reduction of $0.5 million to the Company's test year employee benefits budget.

Regulatory Expenses

3.7.22 Included in the cost of service for the 1991 test year is an amount of $4.1 million for regulatory expenses. This represents an increase of $1.7 million over the budgeted and Board approved level for the 1990 fiscal year and $1.2 million over the amount actually spent in that year. The evidence disclosed that $1.9 million or almost half of the total regulatory expense budget for the 1991 test year is related to National Energy Board matters. This level of expense represents an increase of 36 percent over that estimated for 1990.

3.7.23 The Company explained the increase of $1.2 million spent in 1990 as being mainly due to the inclusion of $0.5 million for the pending OEB integrated resource planning generic hearing and $0.5 million relating to its involvement in the NEB GH-5-89 TCPL facilities expansion and toll design hearing, which cost was incurred in 1990 but deferred to the 1991

test year. The balance of the increase was attributed by the Company to the current hearing not being a limited issues hearing as was E.B.R.O. 464.

3.7.24 Board Staff submitted that it would be more appropriate to apportion costs relating to generic matters over more than one year. It suggested that only $200,000 of the costs of the pending IRP hearing be included in the 1991 test year and the balance be deferred to the 1992 fiscal year. With respect to the NEB related budgeted expenses, Board Staff argued for a total reduction of $475,000 to reflect a $100,000 reduction in general regulatory work activity, the removal of $174,000 relating to the MacKenzie Delta facilities hearing, and a $200,000 reduction to reflect anticipated savings from a greater coordination of the interventions of the Ontario gas utilities.

3.7.25 F & V submitted that the Board should allow the Applicant's regulatory expenses only if the Application is denied. It also argued that the costs related to NEB's GH-5-89 should be disallowed on the basis that the Applicant "failed to challenge" TCPL's proposals.

3.7.26 Energy Probe submitted that the Company's budgeted legal expenses for regulatory matters are excessive. It argued that the billing rates for counsel representing the Company before the NEB are high in relation to those charged by counsel representing the Company before this Board, and in relation to the rate for counsel representing Board Staff. Energy Probe pointed out that NEB counsel billable hours could be cut in half if Consumers Gas only retained a senior counsel and argued that ratepayers "should not be funding the training and education of a back-up counsel". With respect to the legal expenses for Company's counsel before this Board, Energy Probe argued that the billable hours should be cut to less than half on the basis that Consumers Gas is also seeking to recover the $2.2 million annual cost of its regulatory department which should bear prime responsibility for preparing the Company's prefiled evidence and argument.

3.7.27 Energy Probe also submitted that the Board's test for determining a utility's allowed level of regulatory costs should be no different than the test determining the allowed level of regulatory costs for an intervenor.

3.7.28 IGUA submitted that the reasonable costs incurred by the Company's participation in the regulatory proceedings of those utilities which provide transportation and storage services to it should be recovered. IGUA pointed out that, if the Board is concerned with the rates being charged to Consumers Gas by professional advisors, an assessment of a sample of these accounts could be carried out by either the Board's Assessment Officer, or by a judicial official skilled in the assessment of such activity.

Board Findings

3.7.29 The Board notes that the Applicant agreed with Board Staff's proposal to defer a portion of the regulatory costs associated with the upcoming IRP hearings to the Company's 1992 fiscal year. The Board concurs and finds that $200,000 shall be removed from the Company's 1991 regulatory expense budget for this purpose.

3.7.30 The Board considers it important that the interests of Ontario's natural gas consumers be represented in pertinent hearings before the NEB. Given that these interests are largely shared by the ratepayers of all three major Ontario utilities, the Board concurs with Board Staff's contention that a greater degree of cooperation in mounting common interventions should be sought. Toward this end, the Board finds that the Company's budgeted costs for interventions before the NEB shall be reduced by $100,000 as a reflection of the savings that are deemed to be achievable through cost-shared interventions.

3.7.31 The Board has reviewed the Applicant's proposed budget in light of the scope and complexities of the regulatory involvements that are anticipated

in the test year. The Board finds that the proposed participation is reasonably required in order to satisfy the onus placed upon the Company, and its need to protect the interests of all its ratepayers. The Board further finds that, with the exception of the above noted adjustments, the Applicant's proposed regulatory expenses are prudent and necessary to achieve the quality of the representations that are reasonably required.

3.7.32 The Board views Energy Probe's argument regarding billing rates for counsel and hours billed as being somewhat self-serving. After considering this argument, the Board concludes that Energy Probe's proposals have failed to differentiate between the mandated full participation of an applicant from the voluntary selective participation of an intervenor, and the quantity of effort required of the various parties.

3.7.33 The Board finds no merit in F & V's position on this matter and rejects F & V's proposal as being inappropriate and of no assistance to the Board.

Arbitration Expenses

3.7.34 An amount of $300,000 has been budgeted for the 1991 test year to cover an arbitration expense which is expected to be incurred in the summer of 1991. Board Staff argued that, to the extent these expenses will be incurred, they should be applied to the 1992 fiscal year since they are associated with that year's gas supply arrangements. In reply argument, the Company agreed to defer this amount to the 1992 budget.

Board Findings

3.7.35 The Board agrees to the deletion of $300,000 from the test year budget on the basis that these arbitration expenses should be applied against the test year in which they will have impact.

Sales and Marketing Expenses

3.7.36 The sales and marketing budget for the test year is $13.0 million exclusive of $1.6 million relating to the NGV program. These proposed levels of expenditure represent an increases of 11.04 and 20.2 percent, respectively, over the estimated levels for 1990. Included in the $13.0 million is an amount of $2.6 million relating to marginal non-sales promotion, an activity involving the servicing of the needs of builders and developers. The $2.6 million amount represents an increase of 19.8 percent over that for 1990.

3.7.37 IGUA submitted that sales and marketing costs are the type of expenditures that can reasonably be reduced in a recessionary environment. It stated that there is no valid reason for the sales and marketing costs to increase at more than the rate of inflation for the test year and suggested a reduction of $0.6 million.

3.7.38 F & V stated that, in recognition of the need to conserve natural gas, no marketing costs ought to be allowed in the cost of service.

3.7.39 Board Staff argued that since the marginal non-sales promotion activity is, according to the evidence, driven by the level of construction activities, the rate of increase should be held to the rate of inflation. It calculated that a downward adjustment of $0.3 million ought to be made to the Company's proposal.

3.7.40 Consumers Gas claimed that Board Staff had "misunderstood" the Company's evidence, and that Board Staff's proposed adjustment was, therefore, inappropriate.

Board Findings

3.7.41 The Board again urges the Company to make greater use of generic advertising in coordination with other Ontario gas utilities as a means toward restraining costs.

3.7.42 The Board notes Consumers Gas' contention that Board Staff has misunderstood the Company's evidence on this item of expenditure. Nevertheless, the Board finds that Consumers Gas has failed to convincingly substantiate its proposed increase in the Company's sales and marketing costs. Considering that Consumers Gas has failed to satisfy the onus placed upon it as the applicant, the Board concurs with IGUA that the Company's sales and marketing budget should be constrained to only an inflationary increase. The Board, therefore, finds that the sales and marketing budget for the test year shall be reduced by $0.6 million.

3.8 NON-UTILITY COST ELIMINATION

3.8.1 An amount of $3.5 million was eliminated from the Company's total administrative and general expenses in the test year, which amount represents the costs associated with the non-utility functions performed by certain Company personnel and departments in the test year. This amount is the net of the $8.0 million total non-utility expenses forecast minus an amount of $5.8 million forecast to be recovered through direct billing and management fees to a number of affiliated companies, plus an adjustment amount of $1.3 million.

3.8.2 Operating expenses for the Company's corporate head office were forecast at $1.1 million of which $53,000 was considered to be non-utility expenses.

3.8.3 The Company's witnesses testified that officers and department heads are responsible for the identification of salaries and expenses incurred in non-

utility activities, but acknowledged that there is no policy defining the method of allocation to be used.

3.8.4 F & V argued that none of the costs associated with the corporate office should be included in the cost of service.

3.8.5 IGUA submitted that in the absence of a policy prescribing the manner in which time allocations are to be recorded, the reasonableness of the non-utility eliminations cannot realistically be assessed. Further, IGUA submitted that a time and cost reporting system on at least a bi-monthly basis be implemented. Arguing that the proposed $3.5 million for the test year is understated, IGUA suggested that this amount be increased by 10 percent.

3.8.6 With respect to the non-utility elimination pertaining to the corporate head office, Board Staff argued that the Company's methodology, whereby space is specifically allocated to personnel who are considered to be incremental to the Ontario utility operations, results in an amount which is only a fraction of the true non-utility activity. It submitted that the Company ought to use a methodology similar to that employed by TCPL whereby office expenses are allocated to non-regulated areas on the basis of salaries. For purposes of the test year, Board Staff stated that the $53,000 non-utility elimination for the Company's head office is "grossly understated" and reasoned that an additional $270,000 should be allocated to non-utility activity.

3.8.7 Board Staff submitted that a policy ought to be established setting out a standard for the information to be provided to support expense allocations, and that corporate departments ought to provide quarterly dockets to justify their time estimates. Board Staff also submitted that the Company should update its management agreements with its subsidiaries. Further, it stated that the Company should address, in its next rates hearing, the issue of

why itemized costs and expenses related to corporate activity are not provided when allocating non-utility expenses.

Board Findings

3.8.8 The evidence presented in this hearing indicates that the Company's accounting of non-utility costs is informal and infrequent, and lacks a governing policy to assure consistency across the organization.

3.8.9 The Company is directed to define a policy statement and guidelines to clarify the need and purpose for identifying non-utility costs, in order to assist individual departments in their efforts to properly account for these costs.

3.8.10 The Board further directs the Company to conduct an internally or externally audited department-by-department review and to mount a credible defence of its non-utility eliminations, and the process by which they were defined, at its next main rates case. For the purposes of this Decision, the Board finds the evidence presented does not credibly substantiate the proposed level of non-utility cost eliminations for the test year. The Board considers the proposed level to be substantially below what would reasonably be expected for an organization of the size and complexity of Consumers Gas.

3.8.11 The Board, therefore, deems that the level of non-utility cost eliminations for the test year be increased by $300,000 reflecting the recommendations by Board Staff and others.

3.9 INCOME TAX RATES

3.9.1 The Company budgeted for a one percent increase in each of the federal and provincial income tax rates effective April 1, 1991. Since these increases are considered to take effect in mid-fiscal year, the combined annualized effect is an increase of one percent to 44.5 percent for the test year.

3.9.2 As an alternative, the Company stated that it was prepared to establish a variance account to capture changes in income tax expenses brought about by new taxes or changes in income tax rates.

3.9.3 IGUA suggested that an increase in the combined income tax rate is speculative and argued that contingencies which are "either possible but improbable or possible but speculative" ought not to have an influence on the cost of service for the test year. It however submitted that if the Board is satisfied that an increase in the rate is likely, the route of a variance account should be preferred provided that it is recognized that the proliferation of variance accounts reduces risk, and that the rate of return allowed ought to be adjusted accordingly. Board Staff agreed with the Company's variance account alternative.

3.9.4 While not directly related to the issue at hand, F & V suggested that either the Company pay to the government the full amount of taxes calculated on the basis of the stand-alone concept, or that ratepayers share the tax amount allowed in rates but not payable to the government. It further suggested that since the utility part of the Company is not itself a corporation, the large corporation tax ought not to be part of the utility cost of service.

Board Findings

3.9.5 The Board takes note that the February 26, 1991 federal budget gives no indication of a planned corporate income tax increase during the test year.

3.9.6 The Board considers the potential that a significant provincial corporate income tax increase will be enacted during the test year to be uncertain at this time.

3.9.7 The Board, therefore, rejects the Company's proposed provisions for federal and provincial income tax increases in its test year budget.

3.9.8 In preference to establishing a deferral account at this time, should corporate income tax increases of significance be encountered during the test year, the Applicant may apply to the Board for an Accounting Order to defer these costs, providing that the size and timing of such increases merit such attention.

3.10 BOARD ADJUSTMENTS TO UTILITY INCOME

3.10.1 Giving effect to the Board's findings and adjustments contained herein, the Board determines that an amount of $73.4 million shall be allowed for the Company's test year depreciation and amortization expense, and an amount of $33.4 million for its income taxes expense.

3.10.2 The Board, therefore, finds the Company's Ontario Utility Income in the 1991 test year to be $186.1 million, as shown in Appendix A.

4. ONTARIO UTILITY RATE BASE

4.0.1 The Company determined the test year rate base to be $1,707.6 million which incorporated a proposed capital budget of $190.7 million. The items comprising rate base are shown in Appendix B.

4.0.2 The Board has determined that, for the purposes of this Decision, the following issues needed to be addressed:

- Plant Held for Future Use
- General Plant
- Feasibility Analyses of System Expansions
- Cash Working Capital

4.1 PLANT HELD FOR FUTURE USE

4.1.1 In its E.B.R.O. 464 Decision the Board directed the Company to:

- make accounting entries, establishing inactive services of over two years, to the Gas Plant Held For Future Use account;

- satisfy the Board in future that any inactive assets to be included in the Company's rate base are "used or useful"; and

- establish a system to identify unused plant assets and their duration of inactivity.

4.1.2 As of September 30, 1990, the Company made the accounting entries as directed by the Board. However, the Company proposed to reverse those entries for the 1991 test year and make entries to reflect the Company's proposals which are set out below.

4.1.3 Based on the results of an internal study filed at the hearing, the Company proposed to transfer to Account 102 - Gas Plant Held for Future Use, services inactive for 3-15 years but to include them in rate base, claiming that these inactive services have the greatest probability of reactivation.

4.1.4 The Company proposed to depreciate the balance of Account 102 - Gas Plant Held For Future Use, at the accrual rate applicable to Account 473 - Services, on the basis that these services are deemed to be used or useful plant held for future use and are, therefore, a part of its depreciable assets.

4.1.5 The Company also stated that a system to monitor inactive services is now in place. The Company indicated that it is in the process of developing another system to reconcile the operating records of measuring and regulating equipment which system is expected to be operational by the end of 1991.

4.1.6 With respect to establishing a system which, in addition to identifying other unused plant assets, would monitor and display their duration of inactivity, Consumers Gas explained that an internal study showed that property not in use is routinely retired from plant in service. What remains in rate base is plant which is either in use, or will be used in the near future. The Company concluded that these other asset accounts do not warrant further monitoring.

4.1.7 Board Staff argued that the sample selection used by the Company cannot be used to determine the probability of reactivation. It explained that, if a service is reactivated, it is more probable that the service was inactive for less as opposed to greater than fifteen years. It argued that the Company should enhance its computerized monitoring database by including historical reactivation records in order to determine trends and to assist in the calculation of probabilities.

4.1.8 Board Staff further argued for the removal from rate base the net book value of inactive services held in Gas Plant Held For Future Use, and the associated depreciation expense from utility income, on the basis that the Company failed to provide any evidence that any of the inactive services have a probability of being reactivated.

Board Findings

4.1.9 The Board is encouraged by the promptness with which Consumers Gas has reacted to the directions in its E.B.R.O. 464 Decision with regard to the treatment of Plant Held for Future Use.

4.1.10 The "study", presented by Mr. Katugampola on behalf of the Company in this matter, serves to establish a 15 year horizon for inactive assets held in the Company's plant held for future use. The failure to include retired assets as part of the study's sample unfortunately invalidates the study's further use as an analytical display.

4.1.11 The Board is mindful of the difficulties that the Company is experiencing in coming to grips with this issue in the absence of accurate records. The Board directs the Company to continue its efforts to improve its record keeping to track the age and duration of inactivity for assets being held for future use, and to consider the associated depreciation aspects. The Board acknowledges, however, that the development of an effective accounting

treatment, in compliance with the Board's E.B.R.O. 464 directives, will be an evolutionary effort.

4.1.12 For the purposes of this Decision the Board will allow the Company to retain all inactive services, whose tenure of inactivity is between 3 and 15 years, in its Gas Plant Held for Future Use account. However, the Board sees the failure to include retired assets as part of the Company's study as having resulted in an overstatement of the asset level that should reasonably be considered as potentially useful. The Board, therefore, deems that 50 percent of the gross value of inactive assets or $3.7 million shall be excluded from the Company's rate base in the test year, and that accumulated depreciation shall be adjusted by $.6 million. Depreciation expense shall, for ratemaking purposes, also be adjusted accordingly. However, for accounting purposes the Company is directed to continue to accrue depreciation on the full amount of the inactive services held in the Gas Plant Held For Future Use account.

4.2 GENERAL PLANT

4.2.1 In its E.B.R.O. 464 Decision the Board expressed concern regarding the size and trend of expenditures for general plant. It reduced rate base by $2.0 million for the 1990 test year and expressed an expectation that the general plant account would, in fiscal 1991, show "marked reductions in the rates of spending in almost every subcategory".

4.2.2 The Company forecast its 1991 test year expenditures for general plant to be $9.3 million, exclusive of $43.0 million budgeted for the Equipment on Customers' Premises account. The Company testified that it considered the Board's concerns and scrutinized the items comprising the total amount, but concluded that no adjustments to its spending plans were warranted. In the Company's view, the problem was not the size of the budget, but rather its failure to clearly justify its general plant expenditures to the Board.

4.2.3 Board Staff submitted that the $9.3 million general plant budget is excessive. It pointed out that, while this level is lower than that expected to be spent in 1990, it is substantially higher than the $5.1 million 1989 level, and the average 1986-1989 level of $5.2 million. Board Staff submitted that the Board ought to reduce the level by $3.5 million to bring the average expenditure per employee in the test year to the average level experienced in the 1986-1989 period.

4.2.4 IGUA suggested that, given the recessionary environment and considering the TCPL toll increase, the capital budget can be either reduced or postponed in a number of areas. It suggested that the $1.2 million proposed capital expenditures for tools and work equipment can be easily reduced or postponed, and that $1.5 of the total $2.26 million budgeted for acquisition of replacement furniture can be postponed. IGUA further argued that the need to spend $2.2 million for computer equipment had not been demonstrated to be absolutely necessary, and suggested a reduction of at least $1.0 million in this account.

Board Findings

4.2.5 In the Board's view, in the final analysis, the Company has essentially chosen to disregard the expectations put forward by the Board in its prior decisions.

4.2.6 The Board rejects the Company's contention that, since it does not over-spend in good economic times, it should not be required to reduce spending when the economy declines. The Board notes that, while individual impacts may not be severe, the costs of the Company's spending are ultimately borne by its ratepayers who are already disadvantaged in recessionary times. The Board also rejects the premise that Consumers Gas should act as a spending stimulus to hasten the pace at which the economy recovers. The Board is not aware of any mandate under which

the Company should assume guardianship for the good of the economy at the expense of its ratepayers.

4.2.7 The Board's expectations of cost cutting were clearly stated in its E.B.R.O. 464 Decision, and yet the Company has continued to expend substantial sums on items such as computers and ergonomic furniture. The Board notes that the Company continues to justify these expenditures on the promise of productivity gains which are, in fact, slowing.

4.2.8 The Board concludes that, given the Board's earlier statements of concern over this matter, the added burdens of the GST and an already depressed economy, the Company should not ignore the need for serious cost restraint in its purchases of largely discretionary items. The Board therefore finds that the Company shall reduce its proposed test year capital expenditures budget for General Plant by $3 million without relaxing its safety priorities.

Feasibility Analyses of System Expansions

4.2.9 As is the case with each main rates hearing, the Company submitted a study in this hearing showing the rate of return on the most recent year's increments of system expansion.

4.2.10 The study has three parts which are as follows:

- the Basic Study, which illustrates the rate of return earned on new mains;
- the Service Study, which blends in the return on investment from customers added to existing mains; and

- the Monitoring Study, which updates the preceding four years' studies for the customers actually added to the installed mains represented in those studies.

4.2.11 Board Staff submitted that the most meaningful analysis is contained in the Monitoring Study. Focusing on two of four capital projects presented in the study, Board Staff expressed concern that the customer additions five years earlier have produced a negative net present value and that no corrective action can be taken. Board Staff suggested that in the future the Company should link the results of the Monitoring Study with the results that would have been expected at the time the projects were begun, and use this information to address appropriate changes in the feasibility standards it applies.

4.2.12 Board Staff also suggested that the Company include in its prefiled evidence feasibility analyses for projects which would not be the subject of a leave-to-construct proceeding.

Board Findings

4.2.13 The Board agrees with the Company's claim that it is improper to assess the returns on past system expansions on the basis of an analysis of only a selected few projects. The Board does not consider it necessary to take corrective action in this matter at this time.

4.2.14 The Board reminds all parties that, should it find it necessary to take account of an expansion project which has proven to be grossly over-estimated, the Board can, as a corrective measure, deem a reduction to the initial capital cost of that specific project.

4.3 CASH WORKING CAPITAL

4.3.1 The Company proposed a cash working capital study which employed the Board approved lead/lag methodology, but was modified to reflect the Board's direction in E.B.R.O. 464, i.e. that gas cost disbursement lags should reflect the gas supply mix and terms of payment that will prevail in the test year. The Company also provided a study which estimates the effects of the GST.

4.3.2 The Company also provided an update regarding a number of billing systems and technologies under investigation. Board Staff suggested that, before the Company implements residential automatic meter reading scheduled to begin in fiscal 1992, the Company should produce a cost/benefit analysis.

Board Findings

4.3.3 The Board appreciates the Company's success in reducing its receipts lag to 39.7 days, and its intentions to study ways by which lead/lag ratios can be further improved.

4.3.4 The Board accepts the Company's proposed method of determining cash working capital in the test year. Giving effect to the Board's adjustments to gas costs and O&M expenses found elsewhere herein, the Board finds a cash working capital allowance of $10.7 million for the test year.

4.4 BOARD ADJUSTMENTS TO RATE BASE

4.4.1 In light of the foregoing, the Board finds that the Company's Ontario utility rate base for the 1991 test year shall be adjusted downward by $42.4 million to $1,665.2 million as shown in Appendix B. This level of rate base also incorporates a $2.0 million increase in the Gas in Storage account to reflect the Board's findings herein related to FS-WACOG, and

a $0.8 million downward adjustment to accumulated depreciation. The Board considers the adjusted accumulated depreciation of $474.1 million to be adequate for the test year.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

5.0.1 As noted earlier, evidence on the Company's capital structure and cost of capital for both the 1990 and 1991 fiscal years was put forward in the E.B.R.O. 464 proceeding. In that Decision the Board dealt with the capital structure and cost of capital issues pertaining to the 1990 fiscal year. This Decision will address these issues in the context of the 1991 test year.

5.0.2 Both Board Staff and IGUA argued for a reduction in the deemed common equity component to 33 percent and recommended a rate of return on common equity of 12.95 and 13 percent, respectively, for the 1990 fiscal year. In E.B.R.O. 464 the Board accepted the Company's recommendation of 35 percent common equity, but found that the appropriate rate of return on that common equity was 13.25 percent for the 1990 test year.

5.0.3 During this hearing the Company updated its forecast of the embedded cost of long-term debt and the cost of short-term debt to reflect revised cost rates and delays for placing a $150 million debenture in 1990 and $150 million in 1991.

5.0.4 The Company's capital structure and cost of equity proposals for the test year, including a 14 percent rate of return on a 35 percent common equity component, are summarized in Appendix C. The Applicant, Board Staff, and IGUA all stated that they relied on their positions, argument and

recommendations articulated in the E.B.R.O. 464 proceeding with respect to cost of capital matters. However, referring to Dr. de Bever's evidence in this proceeding, Board Staff recommended a short-term debt cost rate of 11.78 percent compared to the 12.24 level proposed by the Applicant.

Board Findings

5.0.5 The Board accepts the 35 percent common equity component, the 11.91 percent cost of long-term debt and the 8.74 percent cost of preference shares, as proposed for the test year. After considering the evidence in the light of recent trends in the cost of short-term borrowing, the Board finds that the Company's cost of short-term debt shall be 11.5 percent. This rate reflects a Board expectation that prime will average 11.5 percent for the Company's test year. The Board recognizes that the Company can borrow below prime, but the skewness of its short-term debt requirements toward the first two quarters of the test year, when interest rates were high, negates the need to deem a short-term debt cost at a rate lower than prime in this particular case.

5.0.6 As stated earlier herein, the Board views the Company's combined business and financial risk to be marginally lower than in fiscal 1990. The Board, therefore, finds that a reasonable return on common equity for Consumers Gas in the test year shall be 13.125 percent.

5.1 BOARD FINDINGS OF REVENUE DEFICIENCY

5.1.1 The Board has determined the Applicant's rate base to be $1,665.2 million; a reasonable rate of return on that rate base at 12.12 percent; and an indicated rate of return of 11.18 percent. Thus, as shown in Appendix D, the Board finds a gross revenue deficiency of $27.8 million for the 1991 test year.

5.1.2 The method and timing of the recovery of this deficiency are dealt with in Chapter 10 of this Decision.

6. COST ALLOCATION AND RATE DESIGN

6.1 COST ALLOCATION

6.1.1 For purposes of this Decision, the Board has determined that it needs to make specific findings on the following aspects of the Company's proposed cost allocation:

- Allocation of TCPL Demand Related Costs
- Costing of Interruptibles
- Class Homogeneity
- Wholesale Customer Class

Allocation of TCPL Demand Related Costs

6.1.2 The Applicant filed three alternative cost allocation studies which are differentiated by the way the TCPL demand related charges are classified and allocated. These charges were alternatively classified and allocated on the basis of being all demand, all commodity, or demand/commodity.

6.1.3 The Applicant's preferred option was the demand/commodity approach. The Applicant suggested that 60 percent of the TCPL demand related charges should be regarded as having been incurred to respond to its peak day requirements, and 40 percent to respond to its annual demand

requirements. The Applicant proposed to allocate the peak day demand component of such charges on the basis of a three-day coincident peak.

6.1.4 While the aforementioned distribution represents the Applicant's longer-term goal, for the test year it proposed that only 7 percent of the TCPL demand related charges should be allocated on the basis of peak day requirements.

6.1.5 Mr. Vander Veen, the Applicant's expert witness, supported the Company's objectives and testified that the current practice of allocating pipeline costs on a commodity basis results in an over -allocation of such costs to the interruptible and high load factor customers.

6.1.6 Ms. Chown, Board Staff's expert witness, disagreed with the proposed allocation of these costs on the basis that, with the existence of storage enabling the Applicant to purchase at a 100 percent load factor, the peak versus off-peak cost relationship does not apply. She maintained that since the low load factor customers pay for the storage system, the Company's proposal would overcharge these customers.

6.1.7 Board Staff suggested that, while the Applicant's capacity costs on the Union Gas and other transportation systems, where the Applicant's load factor on these systems is about 50 percent, are indeed a function of peak day capacity, this is not the case with TCPL capacity costs. It explained that TCPL capacity accounts for 27.2 percent of the design peak day supply and that, for example, if the peak day demand on the Applicant's system was to decrease, the maximum TCPL capacity would still be maintained. By using the TCPL system at a 100 percent load factor, costs would be minimized. Board Staff submitted that TCPL's demand related costs should continue to be allocated on the basis of annual demand.

6.1.8 Both IGUA and Petro-Canada challenged Ms. Chown's proposal and supported the Company's initiative. IGUA suggested that an 80/20 peak

day/annual demand classification may be demonstrated to be more appropriate. IGUA termed the Company's proposal for the test year as proceeding in "baby steps" and urged the Board to direct the Company "to proceed forthwith" with its 60/40 percent proposal. Petro-Canada suggested that the 60/40 percent peak day/annual volume method should be implemented by the Company in the 1992 fiscal year. F & V, on the other hand, submitted that the TCPL costs included in the cost of service should be treated as 100 percent commodity.

Board Findings

6.1.9 The Board agrees that directionally, and as a longer-term goal, Consumers Gas' proposal to move toward a 60/40 allocation of TCPL demand related charges against peak day/annual demand requirements is appropriate. The Board notes, however, that there is considerable uncertainty over the ultimate impacts of such a move. The Board further notes that there is equal uncertainty as to whether 60/40 is the proper ratio.

6.1.10 The Board, for the present, accepts the Company's specific proposal for the test year, including the use of a three-day coincident peak. The Board endorses the Company's stepwise approach and expects that the Company will monitor and report the impacts as experience is gained at each new demand allocation step.

Costing of Interruptibles

6.1.11 The Company's proposed cost allocation study assumes that the coincident peak of the Rate 170 interruptible class is fully interrupted, while that of Rate 145 is partially interrupted with the result that certain distribution or distribution-related utility investments or operating costs are not allocated to these customer classes.

6.1.12 While Ms. Chown was in agreement with the Company that interruptible customers provide a benefit to the system, she maintained that it is not possible to accurately reflect the benefits of interruptible loads in a traditional embedded cost of service study simply by reducing the allocation of fixed costs to the interruptible customer classes. She suggested that it would be more appropriate to measure benefits by quantifying the long-term incremental costs that would be incurred if these customers were to switch to firm service.

6.1.13 Board Staff submitted that in the future, for purposes of the embedded cost study, the Company should treat interruptible customers the same as firm customers. Board Staff also submitted that the Company reconsider the appropriateness of allocating Gas Supply Administration Expenses based on coincident peak. Further, it suggested that, for the next rates case, the Company should produce a long-run incremental benefit study in order to assess the appropriateness of the interruptible rate discount.

6.1.14 IGUA opposed Ms. Chown's approach to costing interruptible customer classes on the basis that a quasi-firm approach would allocate more than a reasonable level of costs, and result in cost-based interruptible rates which would not provide an adequate differential between interruptible and firm rates. IGUA pointed out that interruptibles switching to firm service would ultimately result in increased costs of service for all customers.

6.1.15 North Canadian and Northridge expressed concern that there may be an over-allocation of costs to firm customers, and suggested that the curtailment credits to interruptible customers should be calculated conservatively, pending a cost study as advocated by Ms. Chown.

6.1.16 Referring to the fact that, when compared to the Company' proposal, Ms. Chown's approach effectively doubles the allocated rate base for interruptible Rate 170, Petro-Canada submitted that, rather than rely on subjective criteria in allocating costs to the interruptible classes, a simpler

method would be not to allocate any costs to these classes. It explained that, since interruptible customers may migrate toward alternate fuels or to firm service, there is a high probability that neither the revenue forecast nor the cost allocation will be correct. Petro-Canada suggested that the Board direct the Company to adopt a system similar to that employed by TCPL where the forecast revenue is subtracted from the cost of service, leaving a net amount to be allocated to the remaining customer classes. Under the TCPL methodology, if less revenue is realized than forecast, the shortfall is deferred and included in the following year's cost allocation. Similarly, if more revenue is realized than forecast, the excess revenue is deferred and deducted from the following year's cost allocation.

Board Findings

6.1.17 The Board shares the view that interruptible customers are critical contributors to a utility's system management capabilities. The Board has maintained that cost-based ratemaking is a desirable regulatory objective. However, external forces heavily influence the fuel choice and service class decisions of the interruptible customer and thus require the recognition of value of service considerations when structuring rates for this customer class.

6.1.18 The Board rejects Board Staff's proposal to treat interruptible customer classes as if they were firm for the purposes of the embedded cost of service study. The Board recognizes the difficulties encountered when attempting to allocate costs to the interruptible classes and agrees that the matter warrants additional consideration. The Board will not, however, require a formal long-run incremental benefit study at this time. The Board does, however, expect that Consumers Gas will continue to attempt to refine or revise its cost allocation practices to reflect cost causality to the degree possible, and along these lines to investigate the merits of TCPL's allocation policy regarding interruptible customers, and to present its appraisal at the Company's next rates case.

Class Homogeneity

6.1.19 Board Staff suggested in argument that the Company's methodology for determining customer related costs, that is by estimating average investment costs which include demand related costs, results in an over-estimation of the customer related costs for each rate class, especially those rate classes with a wide dispersion of load levels. It argued that the "true" customer costs should reflect the costs of attaching a minimum, not an average size customer to the system.

6.1.20 Board Staff suggested that the Company should review its methodology, including a possible reclassification of customers based on homogeneity.

6.1.21 Petro-Canada submitted that a demand/commodity rate structure promotes the recovery of fixed costs through the demand component, and reduces the need for load factor homogeneity among customers within a class. Petro-Canada, however, went on to argue that restrictions ought to be imposed on individual classes to ensure that differing perceptions of what are fixed and what are variable costs do not result in cross-subsidies.

Board Findings

6.1.22 The Board does not consider the current level of homogeneity within the Company's existing customer classes as requiring urgent corrective action. The Board will not, at this time, direct Consumers Gas to change its current method of determining customer related costs, or to reshape its customer classes for the sake of improved homogeneity.

Wholesale Customer Class

6.1.23 Pursuant to a Board direction in E.B.R.O. 452 to develop an appropriate basis for charging Gazifere, the Company, in this hearing, proposed a costing methodology to be used in the next main rates case as the basis for

developing a rate for a new class for wholesale customers. The Company testified that the cost allocation was based on the load characteristics of Gazifere and that it will propose a rate based on negotiations with Gazifere. For the 1991 test year the Company proposed to continue to charge Gazifere on the basis of the current methodology.

6.1.24 Board Staff submitted that the proposed allocation of gas supply administrative costs to this class is inadequate, that the rate should be cost based, not negotiated, and that the cost allocations may become unsuitable as more customers are added to this service.

Board Findings

6.1.25 The Board accepts the Company's proposals regarding the costing methodology to be used in establishing a wholesale customer class. In doing so, the Board acknowledges that refinements to the methodology may be required if, or when, the class expands to include customers beyond Gazifere.

6.1.26 The Board approves the Company's proposed treatment of Gazifere during the test year.

6.2 RATE DESIGN

6.2.1 For purposes of the Decision, the Board determined that it needs to make specific findings on the following aspects of the proposed rate design:

- Gas Supply Distribution Shift
- Unbundled Transportation (Rates 300,305,310)
- Interruptible Rates
- Customer Charges
- Direct Administration Customer Charges
- Winter/Summer Rate Differentials

- Customer Provision of Fuel Gas
- Customer Provision of Unbilled and Unaccounted For Gas
- Revenue Shifts

Gas Supply Distribution Shift

6.2.2 The Company proposed to recover the $221 million associated with demand related pipeline costs from delivery charges as opposed to the gas supply charges currently stipulated in the rate schedules. For those customers who opt for delivery only on the Company's system, the Company proposed to provide a Transportation Service Credit.

6.2.3 IGUA suggested that a less confusing rate design approach would be to specifically identify the two delivery charges, which would eliminate the need for a credit, and would better communicate to the customers the sources of the delivery charges they pay. Board Staff supported IGUA's proposal.

Board Findings

6.2.4 Based on the evidence and arguments before it, the Board finds merit in IGUA's argument that the costs of transportation on Consumers Gas system should be segregated from the costs the Company incurs for transportation on the systems of others.

6.2.5 The Company is directed to separate its distribution and transportation charges in order to more clearly identify and communicate these cost elements in its next main rates application.

Unbundled Transportation (Rates 300, 305, 310)

6.2.6 The Company proposed to change Rates 300 and 305 from a pressure differential based rate to a volume based rate. The Company also

proposed to allow the customers served under these unbundled rates to supply their own unaccounted for gas.

6.2.7 No party opposed these proposals. However, IGUA argued there are practical problems facing a customer who attempts to attain a zero balance in its Load Balancing Account under Rate 310, which is a load balancing service available to customers served under Rate 300 or 305. It submitted that the terms and conditions under that rate should be modified to allow the customer 20 days from the end of the contract year to reach a zero balance in its Load Balancing Account.

6.2.8 Petro-Canada alleged that the Company's practice of allocating forecast losses due to unbilled and unaccounted for gas, equally among all rates classes will cost Petro-Canada approximately $200,000 in the test year. It argued that, in view of the magnitude of such costs, the allocation process should not be made on a unilateral and arbitrary basis in the absence of evidence establishing the actual contribution by each class to the forecast losses. Referring to the Applicant's testimony that part of its initiatives is an audit of field operations, Petro-Canada submitted that such an audit should probe into each rate class' contribution, and that the audit results, together with an appropriate proposal, should be presented by the Company at its next main rates case.

Board Findings

6.2.9 The Board accepts the Company's proposals to convert Rates 300 and 305 to volumetric rather than pressure-based rates, and to allow these customers to provide their unaccounted for gas.

6.2.10 The Board finds as reasonable IGUA's proposal that customers in Rate 310 be allowed 20 days following the end of their contract year to achieve a zero balance in their Load Balancing Account. The Board cautions,

however, that this should be considered to be a maximum grace period which should not be expected to be further extended in the future.

6.2.11 The Board is sympathetic to Petro-Canada's proposal that the costs of unbilled and unaccounted for gas should be based on an audit of the contributions that each customer class makes to these "losses". The Board directs the Company to deal with this issue at its next rates case.

Interruptible Rates

6.2.12 The current price differential in favour of interruptible service, relative to comparable firm service, is approximately 1 cent per m^3. The Company proposed to increase the differential to approximately 1.7 to 2.1 cents. Ms. Chown on the other hand recommended a differential of approximately 1.3 to 1.4 cents. Both parties acknowledged that the appropriate differential is a matter of judgement.

6.2.13 While Board Staff did not oppose the proposed differential for the test year, it argued that the Company ought, in the future, to base the differential on certain studies including an incremental cost study as advocated by Ms. Chown.

6.2.14 Petro-Canada stated that neither an embedded cost study nor a long-run marginal cost study will necessarily arrive at the correct discount. It argued that such studies can perhaps be used as guidelines but the true determination of the appropriate rate of discount arises through customer-company interaction, and, ultimately, through acceptance by the interruptible customers. Referring to the evidence, Petro-Canada suggested that current interruptible rates are high relative to firm rates.

6.2.15 Petro-Canada further submitted that range rates could provide an appropriate response to maintain interruptible load, and suggested that the Company be directed to propose such rates in its next rates case.

6.2.16 IGUA suggested that the proposed differential should be viewed as a minimum requirement. IGUA also argued that the Company ought to be directed to contact its large volume interruptible customers to confirm the appropriateness of its current proposal, and to ascertain their reactions to any further changes to interruptible rates prior to its next main rates case.

Board Findings

6.2.17 The Board recognizes the difficulties facing the Company as it seeks to define appropriate discount rates for interruptible customers that have different value of service perceptions. The Board concurs with the Company's conclusion that the firm versus interruptible differential now needs to be widened. Absent any hard evidence either in support of, or contrary to the Company's proposal, the Board accepts, for the purposes of this hearing, the Company's proposed increase in the differentials to be offered to interruptible customers in the test year.

6.2.18 The Board views the test year as a critical period during which market responses should be tested. The Board directs the Company to revisit the entire subject of cost allocation and rate design for the interruptible class at its next rates hearing, and to bring forward evidence supporting its current treatment or indicating, and justifying, what further changes are required.

Customer Charges

6.2.19 The Applicant proposed to increase its monthly customer charges to the general service customers by $0.50 to $6.50 for Rate 1; by $0.50 to $4.70 for Rate 2; and by $2.00 to $10.00 for Rate 6.

6.2.20 Ms. Chown on the other hand suggested that, because of the "substantial" under-recovery of customer related costs, the monthly customer charges for

Rates 1 and 2 should be increased by $1.00. She advised against an increase above $2.00 for Rate 6 pending a potential split of that rate. Board Staff supported Ms. Chown's suggestions.

Board Findings

6.2.21 The Board concurs that it is desirable to move customer charges closer to customer costs. The Board finds that the smaller adjustments proposed by the Company are preferable to the larger, and partially deferred, increases suggested by Ms. Chown. The Board, therefore, approves the Company's proposed changes to the monthly customer charges in its general service rates.

Direct Purchase Administration Charge

6.2.22 The present rates for direct purchase customers specify a monthly Direct Purchase Administration Charge of $225 per contract, irrespective of the number of service locations contained in the contract. The Applicant proposed to alter this fee by charging a customer a base fee of $92 per contract plus $8 per location, to a maximum total of $500 per month. The minimum charge under the Company's proposal would, therefore, be $100 for a customer with one location, and a maximum of $500 for a customer with 51 or more locations. A customer with 1 to 15 locations would see a reduction in the monthly charge, while a customer with 16 or more locations would see an increase. The Applicant indicated that its proposal would generate the same $1.3 million in revenue that would be obtained using the existing administration fee schedule.

6.2.23 All parties except for Board Staff that commented on the Company's proposal argued against this proposal on the basis that an increase for certain direct purchase customers would be a disincentive to the direct purchase activity, and that the Company had not demonstrated that the $8 charge per location is based on cost causality.

6.2.24 Board Staff suggested that the Company should eventually recover, from these customers, the fully allocated costs associated with this activity, not only the direct costs.

Board Findings

6.2.25 The Board considers the Company's proposed changes to be arbitrary. The Board is also concerned that implementation of the proposed changes could be a disincentive to the furtherance of consortium direct purchasing at a time when customers are most in need of opportunities, such as are provided by buy/sell purchases, to minimize their costs.

6.2.26 The Board, therefore, rejects the Company's proposed changes to the direct purchase administration charge and requires that, pending the filing of new evidence, this charge shall continue to be applied in its current form.

Winter/Summer Rate Differential

6.2.27 The Applicant suggested a modest increase to the differential between winter and summer rates to 1.795 cents per m^3, for customer classes without demand charges, and up to 1.2 cents per m^3 for customer classes with demand charges.

6.2.28 Energy Probe implied that a higher winter/summer residential rate differential would be consistent with the evidence of long-run marginal costs. It further suggested that it would induce consumers to buy more efficient gas furnaces and to switch from electricity to natural gas for base load applications, thereby providing substantial economic and environmental benefits to the Province. Energy Probe submitted that the Company ought to be directed to file, at its next main rates case, a proposal to increase the differential. F & V, on the other hand,

recommended the abolition of seasonal rates on the basis that there is no evidence that lends credence to seasonal rates.

Board Findings

6.2.29 The Board finds that the Applicant's proposed increase in the winter/summer rates differential is reasonable.

6.2.30 The Board agrees with Energy Probe's assertion that increased differentials could have desirable impacts on customer consumption patterns. However, in the Board's opinion, this issue should be left for more thorough investigation as part of the upcoming IRP hearing.

Customer Provision of Fuel Gas

6.2.31 The Ottawa-Carleton Consortium, North Canadian and Northridge, and Petro-Canada argued that the Company should be directed to permit western buy/sell customers to supply their own fuel gas, as is the case for such customers on both the Union Gas and Centra Gas systems. The Applicant submitted that a customer who wishes to provide its own fuel can do so through an Ontario buy/sell or T-Service. The Applicant pointed out that, as the shipper, the customer bears the risks of unabsorbed demand charges.

Board Findings

6.2.32 The Board finds it reasonable that the cost savings opportunity associated with the provision of fuel gas should be extended to western buy/sell customers. The Company is directed, effective April 1, 1991, to allow western buy/sell customers to supply their own fuel gas provided that these customers accept liability for any unabsorbed demand charges they may cause on the TCPL system, and for any costs that may result from the customer's failure to supply the required gas.

Revenue Shifts

6.2.33 The Company proposed a revenue shift to adjust the rates of return for Rates 1 and 6. It proposed to reduce the revenue contribution from Rate 1 by $10 million and to increase the revenue contribution from Rate 6 by the same amount.

6.2.34 Using the Company's proposed revenue generation from each class, and based on her cost allocation proposals, Ms. Chown proposed that the revenue contribution should decrease by $8.0 million for Rate 1, increase by $6.0 million for Rate 6, increase by $7.5 million for the interruptible rates, and decrease by $5.5 million for the firm rates. Board Staff supported Ms. Chown's proposal and further submitted that the Company should consider, at its next rates case, either eliminating Rate 2 or significantly increasing its contribution.

Board Findings

6.2.35 The Board concurs with the Applicant's claim that market response must be taken into account when implementing revenue shifts between customer classes. The Board has elsewhere herein acknowledged the need to reduce the rates to interruptible customers.

6.2.36 The Board, therefore, accepts the revenue shifts proposed by the Company as appropriate for the test year. However, the Board directs the Company to confirm, at its next main rates case, the market acceptance and continued appropriateness of the herein approved revenue shifts, and to specifically address, at that time, the matter of the need for the Rate 2 classification and its appropriate level of contribution.

7. DEFERRAL ACCOUNTS

7.1 EXISTING DEFERRAL ACCOUNTS

7.1.1 The Company requested Board approval for the disposition of the balances in four deferral accounts. Both the principal and interest balances in each account were reported as at September 30, 1990, but the Company proposed to update the interest calculation as of one month prior to the implementation of the Board's Order in this proceeding. The combined balance as of September 30, 1990 in these deferral accounts, exclusive of interest, is a net credit of $3.482 million to be rebated to the Applicant's customers.

7.1.2 The Company proposed that the calculation of the rebate for non-general service customers be based on the fiscal 1990 actual volumes consumed, and that for general service customers it be based on consumption over the most recent 12 month period. The Company testified that, pursuant to the concerns expressed by the Board in its E.B.R.O. 464 Decision, it intends to expand its current billing system to apply general service customer bill adjustments to the relevant period during which the balances were accumulated.

7.1.3 The Company proposed that the updated interest calculations be at the cost rate of unfunded debt approved by the Board in this proceeding.

Heating Value Differential

7.1.4 This account recorded the value of fluctuations in the heating values of gas received by Consumers Gas, as compared to the assumed 37.6 gigajoules per 10^3m^3 upon which the Applicant's current retail rates are based. The credit balance in the account is $2.734 million, which the Company proposed be rebated, together with accrued interest, to all sales customers.

7.1.5 Board Staff argued that, since the marginal cost for the delivery of an additional unit of gas is less than the marginal revenue derived from the sale of that unit of gas, a financial benefit accrues to the shareholder when the actual heat content is below what was budgeted. It pointed out that this has been the case in the last three years and estimated that the Company's shareholders profited by a pre-tax amount of about $5.6 million.

7.1.6 Board Staff also argued that the current practice discriminates against customers who pay a higher than average gross margin but are only compensated on an average basis.

7.1.7 Board Staff submitted that the balance in this account should be recalculated based on an algebraic formula presented in its argument, which uses the average monthly weighted heat content per cubic metre of the gas entering the system, and the actual billed volumes for each rate class, to calculate the marginal volume attributable to the heat content variance. Multiplying this marginal volume per class with the average rate class volumetric rate produces the marginal revenue for each class. This total would be adjusted down by 20 percent to reflect the costs associated with the additional transportation and storage of the marginal unit.

1989 PGVA

7.1.8 This account recorded the difference between the actual prices paid and the forecast prices of gas which underpinned rates charged to customers in the January 1, 1989 to September 30, 1989 period. At September 30, 1990 the account had a net debit balance of $558,000, comprised of a credit balance of $3.853 million related to the TCPL toll reduction to September 30, 1989, and a debit balance of $4.411 million related to gas cost variances during that period.

7.1.9 The Board first reviewed this account in E.B.R.O. 464. In that Decision the Board deferred disposition, and directed the Company, with the cooperation of the Board's Energy Returns Officer, to more fully describe certain elements in the account and to file expanded evidence at its next opportunity. Such evidence was filed in this proceeding.

7.1.10 The Company proposed that the $3.853 million, plus accrued interest, be rebated to all system users, except buy/sell customers who have already had the benefit of the TCPL toll reduction. The Company further proposed that the $4.411 million debit balance, together with accrued interest, be charged to all sales customers.

1990 PGVA

7.1.11 This account recorded the difference between the actual prices paid and the forecast prices of gas which underpinned rates charged to customers in the October 1, 1989 to September 30, 1990 period. At September 30, 1990 the account had a net debit balance of $766,000, comprised of a credit balance of $4.045 million related to an unbudgeted TCPL toll reduction for the period October 1, 1989 to December 31, 1989, and a debit balance of $4.811 million related to gas cost variances during that period.

7.1.12 The Company proposed that the $4.045 million, plus accrued interest, be rebated to all system users, except buy/sell customers who have already had the benefit of the TCPL toll reduction. The Company further proposed that the $4.811 million debit balance, together with accrued interest, be charged to all sales customers.

7.1.13 Board Staff challenged the Company's performance regarding the cost of certain streams of gas that were captured in the account. It submitted that the balances in the 1990 PGVA indicates that there is no incentive for the Company to minimize gas costs, and that there is a need to institute such incentive. Pointing out that both the 1989 and 1990 PGVAs reflect an actual and forecast gas cost differential of less than 1 percent, Board Staff suggested that the PGVA may be redundant and that the Company should consider its discontinuance or replacement with a different arrangement, which would aim at reducing long-term gas supply costs.

Union Gas Rate Differential Account

7.1.14 This account recorded the difference between the actual costs and the forecast costs of Union Gas' transportation and storage services to Consumers Gas, since the Company's forecast costs were based on Union Gas' proposals in E.B.R.O. 462. At September 30, 1990 the account had a credit balance of $2.734 million. The Company proposed that this credit, plus accrued interest, be rebated to all customers.

Board Findings

7.1.15 The Board accepts the Company's evidence with respect to the balances in its existing deferral accounts, and authorizes the disposal of these balances in the manner proposed by the Applicant.

7.2 PROPOSED DEFERRAL ACCOUNTS

7.2.1 The Applicant proposed that the following deferral accounts be either continued or established for the 1991 test year:

- 1991 Purchased Gas Variance Account
- Heating Value Differential Account
- Tecumseh Rate Differential Account
- Deferred Rebate Account
- Customer Selection Variance Account

7.2.2 The first four deferral accounts represent a continuation of the same accounts that operated in the 1990 fiscal year. The purposes of, and proposed accounting methodologies for these accounts is unchanged from those in 1990, except that the applicable period is now the 1991 fiscal year.

Board Findings

7.2.3 The Board approves the establishment of the test year deferral accounts proposed by Consumers Gas with the following exceptions and changes:

- the need for a Customer Selection Variance Account has been obviated by the Board's decision herein not to change the FS-WACOG value at this time; and

- the Heating Value Differential Account shall be based on variances from a new average heating value bench mark of 37.49 MJ/m^3 in keeping with the Board's earlier finding herein.

7.2.4 The Board notes that the balances in the Company's PGVA accounts have, over recent years, dropped to the levels that suggest that these accounts may no longer be necessary. Given this trend, and the fact that PGVA

accounts were initially required to deal with the gas purchasing uncertainties that existed in the early days of natural gas "deregulation", the Board directs Consumers Gas to present evidence at its next main rates case to defend the continuance and form of its PGVA accounts.

8. TCPL TOLL INCREASE

8.0.1 The Company's original filing incorporated the TCPL tolls effective as of January 1, 1990. During the hearing the Applicant became aware of an NEB authorized interim increase in the TCPL tolls effective January 1, 1991. Additional evidence filed by the Applicant on January 16, 1991 indicated the specific impact of the interim toll increase on utility income and rate base. This evidence revealed that the annualized impact of the interim toll increase is approximately $30 million, and the unit increase is $3.051 per 10^3m^3.

8.0.2 The Company requested that the Board approve two sets of rates to reflect the October 1, 1990 to December 31, 1990 period, i.e. the period prior to the TCPL interim toll increase, and the period on and after January 1, 1991 when the increased toll was put into effect. Also, the Company acknowledged that there would be a period following January 1 when the impact of the toll increase would be off-set by inventory credits as the gas already in storage was drawn-down on a first-in, first-out basis.

8.0.3 The Company proposed that gas consumed from October 1, 1990 through to the date when the lower cost gas in storage was deemed to have been consumed ("the start-up date"), would recover the revenue requirements found appropriate by the Board in this Decision, exclusive of the impacts of the interim toll increase, and be reflected in rates ("the EBRO 465

Rates") as found appropriate by the Board in the portion of this proceeding related to rate design matters.

8.0.4 The Company recommended that gas consumed subsequent to the start-up date be governed by the second set of rates ("the EBRO 465/TCPL Rates") which would recover the annualized costs imposed by the interim TCPL toll increase in addition to the above revenue requirements. The Company recommended that the EBRO 465/TCPL Rates might be effective in April 1991.

8.0.5 Under the Company's proposal and assuming that the required Board Orders were in hand, a customer might be billed in April under the EBRO 465/TCPL Rates.

8.0.6 An adjustment would then be determined by calculating the difference between the current Rate and the EBRO 465 Rate and applying the difference to all volumes consumed by that customer between October 1, 1990 and the start-up date.

8.0.7 A second adjustment would be determined by applying the difference between the EBRO 465 and the EBRO 465/TCPL Rates to the customers' volumes between the start-up date and the April billing date.

8.0.8 The Company concluded that the application of the two adjustments would effectively avoid imposing the TCPL interim toll on gas volumes that were exempt from this increase, while still assuring that the Company's authorized rates, as a result of this Decision, i.e. the EBRO 465/TCPL Rates, would recover the found deficiency, including the annualized impacts of the TCPL interim toll increase, from the start-up date onward.

8.0.9 With regard to the impact of the TCPL toll increase on the PGVA, the Company proposed that the PGVA would not be impacted prior to January 1, 1991. On and subsequent to January 1, 1991 the Company's cost of gas

would include the costs associated with the higher TCPL Toll, and these costs are now being recorded in the PGVA.

8.0.10 If, as the Company preferred, the effective date for the EBRO 465/TCPL Rates is the start-up date, these PGVA entries, except for interest cost accruing to the Company, would "no longer be necessary and would be reversed".

8.0.11 The Company offered as an alternative that, if the effective date for the EBRO 465/TCPL Rates was, for example, April 1, 1991 and the Company's WACOG was unchanged until that date, the amount recorded in the PGVA, in respect to the costs of the TCPL interim toll increase from January 1, 1991 through March 31, 1991 would remain in the PGVA for future disposition. On April 1, 1991, coincident with the implementation of the EBRO 465/TCPL Rates, the WACOG benchmark, under the Company's proposed alternative, would increase to include the TCPL interim toll increase's impact on gas costs. Thus, PGVA entries due to the new toll would not be required after that date.

8.0.12 The Company pointed out that, just as two WACOG benchmarks are required, two FS-WACOG prices, one with and one without the impacts of the new toll, will also need to be defined.

Board Findings

8.0.13 The Board concurs with the Applicant's proposal that the impacts of the interim TCPL toll increase should be reflected in the rates which are to be set as a result of this proceeding.

8.0.14 The Board notes that none of the parties commented on, or objected to the Company's proposed options for dealing with the TCPL interim toll increase. Only Board Staff exercised the option, which the Board

provided, for the submission of interrogatories on this matter, and Board Staff's single interrogatory was only of a clarifying nature.

8.0.15 The Board finds that the Company's proposals provide reasonable means by which the costs of the new toll can be fairly recovered. The Board prefers the Company's alternative option since in the Board's view this option offers a desirable degree of simplicity for customer understanding and utility implementation, and the shortfall to be accrued in the PGVA is of manageable proportions.

8.0.16 The Board further finds that the Company's rates to be effective as of April 1, 1991 shall recover, on an annualized basis, the impact of the January 1, 1991 interim TCPL toll increase. The Board directs that any revenue shortfall that might result after reconciling the toll impacts and the gas inventory credits for the period between January 1, and March 31, 1991, shall be accounted for in the Company's 1991 PGVA. The Company's WACOG benchmark to be employed in determining PGVA variances shall also be adjusted as of April 1, 1991 to reflect the interim TCPL toll increase. Any net amounts recorded in the deferral account on and subsequent to January 1, 1991 shall be disposed of in a manner to be determined by the Board at the time that the entire 1991 PGVA account is cleared.

9. COSTS

9.0.1 Section 28 of the Act empowers the Board, at its discretion, to fix or tax the costs of and incidental to any proceeding before it. In its June 1985 Report under Board File No. E.B.O. 116, the Board set out the conditions upon which costs may be awarded.

9.0.2 In argument Energy Probe sought to convince the Board to amend its policies with respect to intervenor costs and the assessment thereof.

9.0.3 The parties petitioning for costs are listed below:

- Industrial Gas Users Association
- Energy Probe
- North Canadian Marketing Inc./Northridge Petroleum Marketing Inc.
- The Ottawa-Carleton Gas Purchase Consortium
- Ontario Housing Corporation

Board Findings

9.0.4 The Board finds that IGUA and the Ottawa-Carleton Consortium acted responsibly and significantly assisted the Board in its understanding of the issues with which they dealt. The Board, therefore, awards both IGUA and the Ottawa-Carleton Consortium 70 percent of their reasonably incurred costs in these proceedings, subsequent to their review by the Board's Assessment Officer.

9.0.5 The Board finds that North Canadian and Northridge assisted the Board by their responsible participation regarding the limited issues which they addressed. The Board awards North Canadian and Northridge 60 percent of their reasonably incurred costs in this proceeding, subject to their review by the Board's Assessment Officer.

9.0.6 The Board has carefully considered Energy Probe's proposals and requests with regard to matters of costs. The Board finds that Energy Probe's argued-for revisions to the Board's current Cost Awards Guidelines remain untested and largely unsubstantiated. Given the broad impacts that could result, the Board concludes that it would be inappropriate for it now to revise its Cost Award Guidelines solely on the basis of the submission of argument by only one intervenor.

9.0.7 The Board finds that it was only marginally assisted by Energy Probe's participation in this proceeding, due largely to this intervenor's heavy focus on issues that are beyond the scope of the specific Application. The Board, therefore, awards Energy Probe 50 percent of its reasonably incurred costs of participation in this proceeding, subsequent to their review by the Board's Assessment Officer.

9.0.8 The Board views OHC's participation in the E.B.R.O. 465 proceeding as having been largely in support of its E.B.R.O. 459 Application. The Board, therefore, finds that the matter of OHC's costs shall be dealt with

in their totality when the Board addresses the matter of costs in its forthcoming E.B.R.O. 459 Decision.

9.0.9 The Board finds that the awarded costs of the above named intervenors, as found by the Board, and the Board's own costs of participation in this proceeding shall be paid by the Applicant upon receipt of the Board's Cost Order.

9.0.10 The Board directs the above named intervenors to submit statements of their reasonably incurred costs of these proceedings to the Board Secretary within 15 working days from the date of the issuance of this Decision.

10. IMPLEMENTATION OF THE DECISION

10.0.1 The Board has found that the combined net deferral account credit balance is $3.482 million, plus accrued interest as of end of February 1991.

10.0.2 Excluding the January 1, 1991 TCPL toll increase, the Board has found a revenue deficiency of $27.8 million for the 1991 test year.

10.0.3 The Board has also found that the Company should recover from its customers the additional gas costs relating to the January 1, 1991 TCPL toll increase.

The E.B.R.O. 465 Rates

10.0.4 The rates in effect at the time of this Decision are those approved in E.B.R.O. 464 and declared interim as of October 1, 1990. These interim rates shall be superseded by the rates which shall include the impacts of the Board's findings herein relating to rate design and to the revenue deficiency found for the 1991 test year. For ease of reference the Board will refer to these new rates as the EBRO 465 Rates.

10.0.5 Given the timing of this Decision, the Board finds April 1, 1991 to be an appropriate date for incorporating the EBRO 465 Rates into the customers' bills. The Board, therefore, authorizes a one-time bill adjustment for the

period October 1, 1990 to March 31, 1991, such adjustment to be the net of the following components:

a) the adjustment arising from the differences that result from applying the EBRO 465 Rates against the now interim rates approved in E.B.R.O. 464 for gas consumed or considered to have been consumed for the period October 1, 1990 to March 31, 1991;

b) the adjustment arising from the disposition of the balances in the deferral accounts, with associated interest, as specified in Chapter 7 herein; and

c) for buy/sell customers, the adjustment arising from applying the FS-WACOG reflected in the EBRO 465 Rates and the FS-WACOG approved by the Board in E.B.R.O. 464.

The E.B.R.O. 465/TCPL Rates

10.0.6 Following the one-time rate adjustment and concurrent thereto, the EBRO 465 Rates shall be adjusted to incorporate the annualized impact of the TCPL interim toll increase. These adjusted rates, referred to herein as the EBRO 465/TCPL Rates, shall be implemented on April 1, 1991 and apply to all gas consumed on that date and thereafter.

10.0.7 The Board recognizes that, since April 1, 1991 is a date later than the "start-up" dates determined by the Company, there will be a revenue shortfall which the Board directs shall be recorded in the 1991 PGVA.

10.0.8 On and after April 1, 1991 the weighted average cost of the Company's gas as reflected in sales rates and employed as the benchmark in determining the amounts to be recorded in the 1991 PGVA shall increase to reflect the impact of the TCPL interim toll increase, and the FS-WACOG shall similarly increase as of that date.

Draft Rate Order

10.0.9 The Board directs Consumers Gas to submit for approval, within 15 business days of the release of this Decision with Reasons, a Draft Order to be accompanied by the following:

i) proposed E.B.R.O. 465 Rates, with appropriate supporting documentation, incorporating the Board's findings relating to revenue requirement and rate design in the test year, excluding the annualized impact of the January 1, 1991 TCPL interim toll increase. The supporting documentation is to include, but not be limited to, the calculation of the allocation of deferral account balances and the calculation of WACOG and FS-WACOG for the applicable period;

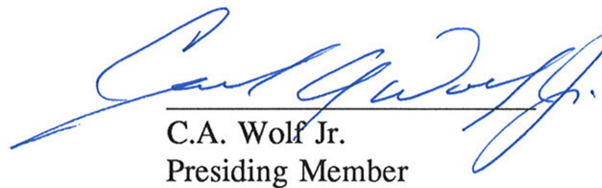
ii) proposed one-time adjustments, with appropriate support documentation;

iii) proposed E.B.R.O. 465/TCPL Rates, with appropriate supporting documentation, incorporating the Board's findings relating to revenue requirement and rate design including the annualized impact of the January 1, 1991 TCPL interim toll increase. The supporting documentation is to include, but not be limited to, the calculation of WACOG and FS-WACOG for the applicable period;

iv) all necessary appendices to reflect the accounting entries in respect of the authorized deferral accounts; and

v) Consumers Gas' drafts of its proposed notices to its customers.

DATED at Toronto this 1st day of March, 1991.



C.A. Wolf Jr.
Presiding Member

S.J. Wychowanec, Q.C.
Chairman

CONSUMERS GAS

ONTARIO UTILITY INCOME

For The Year Ending September 30, 1991

($ million)

	Per Company (a)	Board Adj. (d)		Per Board (c)
Revenue				
Sales and Transportation Revenue	1,593.1	4.7	(1)	1,597.8
Other Operating Revenue	62.8			62.8
Other Income	12.7	(6.7)	(2)	6.0
Total Revenue	1,668.6	(2.0)		1,666.6
Costs and Expenses				
Gas Costs	1,150.1	14.9	(3)	1,165.0
Operation and Maintenance	184.6	(5.1)	(4)	179.5
Depreciation and Amortization	73.7	(0.3)		73.4
Municipal and Other Taxes	29.2			29.2
Total Costs and Expenses	1,437.6	9.5		1,447.1
Utility Income Before Income Taxes	231.0	(11.5)		219.5
Income Taxes				
Without Tax Shield On Interest	91.1	(7.1)		84.0
Tax Shield On Interest	(53.4)	2.8		(50.6)
Total Income Taxes	37.7	(4.3)		33.4
Ontario Utility Income	193.3	(7.2)		186.1

(1) sales volume adj.

(2)
(7.6)	excl. of Merchandise Finance Program
0.9	land sale profit (50%)
(6.7)	

(3)
11.3	FS-WACOG adj.
3.6	sales volume adj.
14.9	

(4)
(2.3)	productivity
(.5)	employee benefits
(.3)	regulatory
(.3)	arbitration deferral
(.6)	sales and marketing
(.3)	non-utility
(.8)	excl. of Merchandise Finance Program
(5.1)	

CONSUMERS GAS

ONTARIO UTILITY RATE BASE

For The Year Ending September 30, 1991

($ million)

	Per Company (a)	Board Adj. (d)		Per Board (c)
Utility Plant				
Gross Plant At Cost	1,934.2	(5.2)	(1)	1,929.0
Accumulated Depreciation	474.9	(0.8)	(2)	474.1
Net Utility Plant	1,459.3	(4.4)		1,454.9
Allowance for Working Capital				
Accounts Receivable Merchandise Finance Plan	44.6	(40.1)	(3)	4.5
Accounts Receivable Rebillable Projects	1.3			1.3
Materials and Supplies	18.7			18.7
Mortgages Receivable	0.7			0.7
Prepaid Expenses	1.4			1.4
Gas in Storage	180.3	2.0	(4)	182.3
Working Cash Allowance	10.6	0.1		10.7
Customer Security Deposits	(9.3)			(9.3)
Total Allowance	248.3	(38.0)		210.3
Ontario Utility Rate Base	1,707.6	(42.4)		1,665.2

(1) (3.7) inactive services (50%)
(1.5) due to $3.0 reduction in general plant
(5.2)

(2) (.6) inactive services
(.2) reduction in general plant
(.8)

(3) due to exclusion of the Merchandise Finance Program

(4) due to FS-WACOG adj.

Appendix C

CONSUMERS GAS

CAPITALIZATION AND COST OF CAPITAL

For The Year Ending September 30, 1991

($ million)

PER COMPANY	Capital Structure	Ratios	Cost Rate	Return Component	Return
	(a)	(b)	(c)	(d)	(e)
Long-Term Debt	929.8	54.45%	11.91%	6.48%	110.7
Short-Term Debt	75.1	4.40%	12.24%	0.54%	9.2
Preference Capital	105.0	6.15%	8.74%	0.54%	9.2
Common Equity	597.7	35.00%	14.00%	4.90%	83.7
Total	1,707.6	100.00%		12.46%	212.8

PER BOARD	Capital Structure	Ratios	Cost Rate	Return Component	Return
	(a)	(b)	(c)	(d)	(e)
Long-Term Debt	929.8	55.84%	11.91%	6.65%	110.7
Short-Term Debt	47.6	2.85%	11.50%	0.33%	5.5
Preference Capital	105.0	6.31%	8.74%	0.55%	9.2
Common Equity	582.8	35.00%	13.125%	4.59%	76.5
Total	1,665.2	100.00%		12.12%	201.9

CONSUMERS GAS

DETERMINATION OF REVENUE DEFICIENCY

For The Year Ending September 30, 1991

($ million)

	Per Company (a)	Board Adj. (b)	Per Board (c)
Ontario Utility Income	193.3	(7.2)	186.1
Ontario Utility Rate Base	1,707.6	(42.4)	1,665.2
Indicated Rate of Return	11.32%	-0.14%	11.18%
Required Rate of Return	12.46%	-0.34%	12.12%
Deficiency in Rate of Return	1.14%	-0.20%	0.94%
Net Revenue Deficiency	19.5	(3.8)	15.7
Provision for Income Taxes *	15.6	(3.5)	12.1
Gross Revenue Deficiency	35.1	(7.3)	27.8

* Income tax rate at 43.5%