E.B.R.O. 493
E.B.R.O. 494
E.B.O. 177-09
E.B.R.L.G. 34-19

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

AND IN THE MATTER OF an Application by Centra Gas Ontario Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 1997;

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 1997;

AND IN THE MATTER OF Applications by Centra Gas Ontario Inc. and Union Gas Limited for Board approval of an affiliate transaction in excess of $100,000 and dispensation from compliance with certain undertakings for the payment of charges to Westcoast Energy Inc. related to the provision of services to Centra Gas Ontario Inc. and Union Gas Limited during the calendar year 1996.

BEFORE: G.A. Dominy
Vice-Chair and Presiding Member

P.W. Hardie
Member

H.G. Morrison
Member

R.M.R. Higgin
Member

DECISION WITH REASONS

March 20, 1997

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1. INTRODUCTION

1.1 THE PROCEEDING

1.1.1 On March 27, 1996, Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra") (collectively "the Utilities" or "the Companies") applied to the Ontario Energy Board ("the Board") pursuant to 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, transmission and storage of natural gas based on projected results effective for each of the Companies' test years commencing January 1 and ending December 31, 1997, ("the 1997 fiscal year", "the 1997 test year", "test year" or "1997").

1.1.2 Centra's Application was assigned Board File No. E.B.R.O. 493 and Union's Application Board File No. E.B.R.O. 494 (collectively "the Applications" or "the 1997 Rate Applications"). In view of the sharing of services between Union and Centra ("Shared Services"), each Company requested a consolidated hearing for the purpose of determining rates and other charges for the 1997 fiscal year. As of December 31, 1995, Union changed its fiscal year to the calendar year to coincide with Centra's fiscal year.

1.1.3 The Board issued Notices of Application for E.B.R.O. 493 and E.B.R.O. 494 on April 2, 1996.

1.1.4 On December 16, 1992 Westcoast Energy Inc. ("Westcoast"), related affiliates and Union provided Undertakings to the Lieutenant Governor-in-Council for the Province of Ontario ("the LGIC") in respect of Westcoast's indirect takeover of Union. These were subsequently amended in 1996 ("the Union Undertakings" or "the Undertakings").

1.1.5 Effective December 11, 1989 Westcoast related affiliates and ICG Utilities (Ontario) Ltd. (now Centra) gave Undertakings in consideration of the LGIC granting leave to permit Westcoast's indirect takeover of Centra. These were subsequently amended in 1992 and 1996 ("the Centra Undertakings" or "the Undertakings").

1.1.6 An Application dated February 6, 1996 was received from Centra and Union for Board approval of affiliate transactions in excess of $100,000 and dispensation from compliance with their respective Undertakings for the payment of charges to Westcoast related to the provision of services to the Utilities during 1996 ("the Undertaking Applications"). For Union the Board assigned File No. E.B.O. 177-09 and for Centra, File No. E.B.R.L.G. 34-19. On April 26, 1996 the Board advised the Utilities that the Undertaking Applications would be heard in conjunction with the E.B.R.O. 493 and E.B.R.O. 494 Applications.

1.1.7 Pursuant to Procedural Order No. 1 issued on May 29, 1996, the parties to the proceeding met on June 26, 1996 for the purpose of developing an issues list. On June 28, 1996, Procedural Order No. 2 was issued which contained the Board-approved issues list. The Order made provision for intervenors to file all interrogatories as Centra specific, Union specific, and joint Utility Shared Services specific.

1.1.8 A technical conference was held on July 2 and July 3, 1996, among the Utilities, Board Staff and intervenors to review the prefiled evidence of the four Applications. A second technical conference was held on August 14, 1996, for the purpose of clarifying the responses to the interrogatories.

1.1.9 On August 28, 1996, the Board issued Procedural Order No. 3 announcing the hearing schedule and Procedural and Motions Day and providing for an Alternative Dispute Resolution ("ADR") settlement process.

1.1.10 On September 3, 1996, the Coalition of Eastern Natural Gas Aggregators and Sellers ("CENGAS") filed a Notice of Motion requesting certain orders from the Board. CENGAS filed an amended Notice of Motion dated October 1, 1996 ("the CENGAS Motion").

1.1.11 The Board issued Procedural Order No. 4 on September 27, 1996 which granted the parties to the ADR settlement process an extension to the date for filing an agreement to October 2, 1996. Pursuant to the Order, the CENGAS Motion was scheduled to be heard on Procedural and Motions Day, October 16, 1996, with the hearing of evidence to commence following the conclusion of the hearing of the CENGAS Motion.

1.1.12 The CENGAS Motion was heard during three days beginning October 16, 1996 and argued on October 31 and November 1, 1996. At the conclusion of argument the Board reserved its decision on the CENGAS Motion.

1.1.13 Notices of Motion were filed with the Board by Union on October 21, 1996 and by Centra on November 8, 1996. These Motions were given Board File Nos. E.B.R.O. 493-01 and 494-01 ("the E.B.R.O 493-01 and 494-01 Interim Rate Motions"). Both Motions requested an order pursuant to subsection 15 (8) of the Act, establishing interim increases in rates and other charges effective January 1, 1997, and in the reference price used to determine amounts to be recorded in certain gas supply related deferral accounts, and in the price payable for gas purchased by each Company under buy/sell contracts.

1.1.14 The oral hearing of the evidence lasted 24 days ending on November 21, 1996. The argument phase was completed on December 17, 1996. On November 27, 1996 the Board issued Oral Decisions on the E.B.R.O. 493-01 and 494-01 Interim Rate Motions approving an interim increase in rates regarding forecast gas supply related costs effective January 1, 1997.

1.1.15 The Board issued its E.B.R.O. 493-01 and 494-01 Interim Rate Orders on December 24, 1996. Centra's Quarterly Rate Adjustment Application was also approved in the E.B.R.O. 493-01 Interim Rate Order.

1.1.16 On January 27, 1997 Union filed a Notice of Motion with the Board requesting the Board to vary its E.B.R.O. 494-01 Interim Rate Order to reflect Union's higher forecast cost of gas for 1997. The Board issued its E.B.R.O. 494-02 Interim Rate Order on February 17, 1997.

1.1.17 On January 28, 1997 Centra applied pursuant to its Quarterly Rate Adjustment Mechanism for an order increasing rates on an interim basis effective March 1, 1997 to reflect higher forecast gas costs. The Board issued its E.B.R.O. 493-02 Interim Rate Order on February 17, 1997.

1.2 THE ALTERNATIVE DISPUTE RESOLUTION SETTLEMENT AGREEMENT

1.2.1 The ADR settlement conference was held by the parties from September 12 to September 20 and on September 25, 1996. The resultant ADR Settlement Agreement (or "the Agreement") dated October 2, 1996 was presented to the Board for its review and consideration.

1.2.2 On the first day of the hearing, the Board advised the parties that, subject to clarification or provision of additional information on certain matters, the evidentiary base on the issues that had been agreed to in the ADR Settlement Agreement was sufficient to allow the Board to make a determination on the issues set out in the Agreement.

1.2.3 During the hearing, Union and Centra, at the request of the Board, filed Errata to the Agreement which included corrections to evidentiary references in the Agreement. The Board agreed that the following additional issues proposed by the parties to the Agreement would also be addressed in the hearings:

- Terms and Conditions of Storage and Transportation ("S&T") Services; and
- Interruptible Rates and Policies.

1.2.4 The Demand Side Management ("DSM") issue was dealt with separately during the discussions in the ADR settlement conference and included as a separate schedule to the Agreement.

1.3 APPEARANCES

1.3.1 The following is a list of active participants who also filed argument and the names of their representatives at the hearing:

Board Staff	Ian Blue Jennifer Lea
Union and Centra	Patricia Jackson Glenn Leslie Michael Penny
Canadian Industry Program for Energy Conservation ("CIPEC")	Beth Symes
Cibola Canada Energy Marketing Co. ("Cibola")	Richard Baker
The Coalition of Eastern Natural Gas Aggregators and Sellers ("CENGAS")	David Brown
Comsatec Inc. ("Comsatec")	Paul Waque
The Consumers' Association of Canada ("CAC")	Robert B. Warren
The Consumers' Gas Company Ltd. ("Consumers' Gas")	Fred Cass Gerry Farrell
Direct Energy Marketing Limited ("Direct Energy") Natural Resource Gas Limited ("NRG") PanEnergy Marketing Limited Partnership ("PanEnergy") Canadian Independent Gas Marketers Association ("CIGMA")	Peter Budd
ECNG Inc. ("ECNG") The London School Board Consortium	J. Thomas Brett

("the London School Board" or "Schools"); Canadian Association of Energy Service Companies ("CAESCO")	
Energy Probe Foundation ("Energy Probe")	Mark Mattson
Enron Capital and Trade Resources Canada Corp. ("Enron")	Aleck Dadson
The Green Energy Coalition ("GEC")	David Poch
The Heating, Ventilation and Air Conditioning Contractors Coalition Inc. ("HVAC")	Ian Mondrow
Industrial Gas Users Association ("IGUA")	Peter C.P. Thompson
Corporation of the City of Kitchener ("Kitchener")	J.Alick Ryder
London GasSave	James Gruenbauer
Northland Power ("Northland")	Michael Hopkins
NOVA Chemicals (Canada) Ltd. ("NOVA" or "NOVA Chemicals")	Michael Peterson Kimberly Poster Mark Opashinov
Novagas Clearinghouse Ltd. ("NCL") and Terra International (Canada) Inc. ("Terra")	Guy Pratte Martine Richard
Ontario Coalition Against Poverty ("OCAP")	Michael Janigan
The Ontario Native Alliance ("ONA")	Nils Connor
Pollution Probe Foundation ("Pollution Probe")	Murray Klippenstein
TransCanada Gas Services Limited ("TCGS")	Mark Stauft
TransCanada PipeLines Limited ("TCPL")	Murray Samuel
The University Group of South Western Ontario ("UGSWO" or "the Universities")	Michael Morrison

1.4 WITNESSES

1.4.1 Union and Centra called the following employees as witnesses:

D. David Bailey	Manager, Market Planning and Evaluation
John Bergsma	President and Chief Executive Officer
Garry D. Black	General Manager, Marketing and Sales, Storage and Transportation
J. Patricia Elliott	Manager, Rates and Cost of Service
Angelo P. Fantuz	Manager, Gas Acquisition
Ali A. Hassan	Manager, Rate Design
A. Fred Hassan	Director, Gas Supply
Donald S. Heath	Vice-President, Retail Energy Services
David A. Hockin	Manager, Distribution Business Development
Patrick J. Hoey	Director, Environment & DSM
William G. James	Manager, Storage Development
William R. Killeen	Manager, Gas Supply Planning
John A. Korol	Manager, Gas Control
Michael W. Packer	Manager, Cost of Service
Violet J. Patterson	Manager, Storage Planning
Bruce E. Rogers	General Manager, Major Industrial Markets
Christopher R. Shorts	Manager, Industrial Gas Delivery Services
Michael A. Stedman	Manager, Transportation
Peter Vilks	General Manager, Business Markets

John W. Wellard	Vice-President, Distribution Operations
Janet P. Woodruff	Controller

1.4.2 Union and Centra also called the following witnesses:

Gordon R. Barefoot	Partner, Ernst & Young Management Consultants ("Ernst & Young")
Wayne M. Bingham	Vice-President, Finance and Treasurer, Westcoast
Murray G.K. Davidson	Partner, Arthur Andersen & Co. ("Arthur Andersen")
Russell A. Feingold	Vice President, R.J. Rudden Associates, Inc. ("RJRA")
Marion E. Fraser	President, SRC Canada

1.4.3 CENGAS called the following witnesses:

G. Bruce Flood	Director of Marketing and Contract Administration, Municipal Gas Association
Gerald Haggarty	Vice-President of Marketing, Alliance Gas Management Inc.
Anthony C. Lewis	General Manager, EnerShare Technology Corporation
Richard R. Perdue	Utility Regulatory Consultant
R. Paul Woods	President, Alliance Gas Management Inc.

1.4.4 IGUA called the following witnesses:

Ted Bjerkelund	Executive Director, IGUA
Lauri Gregg	Manager, Energy and Technical Services, Falconbridge Limited

Brian E. Howell	Consultant
Alisdair Stark	Supervisor, Raw Materials and Energy Purchasing, Bayer Rubber Inc.

1.4.5 ECNG called the following witnesses:

James N. McMahon	President, ECNG Inc.
Peter F. Scully	Manager, Regulatory Affairs, ECNG Inc.

1.4.6 TCPL called the following witnesses:

James D. Bartlett	Supervisor, Regulatory Evaluations and Analysis, TCPL
Thomas E. Gaw	Manager, Gas Control Operations, TCPL
Tibor E. Haynal	Consultant, Haynal Associates
Thomas R. Hughes	Consultant, Thomas R. Hughes & Associates, Inc. ("TRH&A")

1.4.7 GEC called the following witnesses:

Phillip H. Mosenthal	Senior Vice President, Optimal Energy Inc.
John J. Plunkett	President, Optimal Energy Inc.

1.4.8 Consumers' Gas called the following witnesses:

Juri Otsason	Director, Transportation and Transactional Services, Consumers' Gas
Herbert J. Vander Veen	Consultant, Energy Group Inc.

1.5 THE EVIDENCE AND POSITIONS OF THE PARTIES

1.5.1 Copies of the ADR Settlement Agreement together with all the evidence, exhibits, and arguments filed in the proceeding, and a verbatim transcript of the hearing, are available for review at the Board's offices.

1.5.2 The Board has considered all the evidence, submissions and argument in the proceeding, but has summarized the evidence and positions of the parties only to the extent necessary to clarify the issues on which the Board has determined that a decision should be made.

1.6 LETTERS OF CONCERN

1.6.1 The Board received twenty letters of concern. One customer objected to the practice of retroactive billing by the Companies, while other customers objected to the Companies' proposed rate increases. The Board also received several letters of concern from Centra's Rate 16 and Rate 25 interruptible customers. The issues raised by the interruptible customers are addressed in Chapter 10, Centra Cost Allocation and Rate Design.

2. RATE BASE

2.1 UNION AND CENTRA UTILITY RATE BASE

2.1.1 The proposed 1997 Utility rate base for Union ("1997 Union Rate Base") as filed, was $2,134,852,000 made up of net utility plant of $2,302,769,000, an allowance for working capital of $160,208,000, less accumulated deferred income taxes of $328,125,000.

2.1.2 The proposed 1997 Utility rate base for Centra ("1997 Centra Rate Base", collectively "Rate Bases") as filed, was $772,540,000 made up of net utility plant of $742,469,000 and working capital and other components of $30,071,000.

2.1.3 In calculating their 1997 Rate Bases, the Companies used the average of monthly averages method for calculating property plant and equipment.

2.1.4 Union and Centra proposed the removal of their merchandise financing programs ("MFPs") from utility operations effective January 1, 1997, and this was reflected in the proposed Rate Bases.

2.1.5 As part of the ADR Settlement Agreement, the parties agreed that the Companies' MFPs should remain in the cost of service for the 1997 test year. The agreement on the MFPs and other specific items that impact the 1997 Costs of Service as well as Rate Bases are described in Chapter 3 of this Decision. The Companies filed revised Rate Bases to reflect the ADR Settlement Agreement. As a result of the inclusion of the MFPs the Companies' Rate Bases increased. These changes are summarized in Table 2.1.

Table 2.1: 1997 Rate Base

1997 Rate Base ($ million)						
	UNION			CENTRA		
	Filed	**ADR Adjustment**	**Revised**	**Filed**	**ADR Adjustment**	**Revised**
Gross plant [1]	3142.4	(3.3)	3139.1	994.5	(4.7)	989.8
Accumulated Depreciation	(839.6)	0.2	(839.4)	(252.0)	0.1	(251.9)
Net plant	2302.8	(3.1)	2299.7	742.5	(4.6)	737.9
Working capital & other components [2]	160.2	81.3	241.5	30.0	24.2	54.2
Deferred Taxes [3] [4]	(328.1)	1.1	(327.0)	not applicable		
TOTAL RATE BASE	**2134.9**	**79.3**	**2214.2**	**772.5**	**19.6**	**792.1**

Footnote
1 for Centra gross plant includes $0.3 million for Lakeland Organization expense
2 retention of the financing programs in the cost of service
3 adjustment to accumulated deferred taxes reflects agreement to apply flow through taxes to Union's rental program
4 $262.2 million relates to Union's utility operations

2.1.6 The parties to the ADR Settlement Agreement agreed that Centra's evidence and proposals with regard to working capital for 1996 and 1997 should be accepted. With the exception of Board Staff, parties also agreed that Union's evidence and proposals on working capital for 1996 and 1997 should be accepted. Board Staff reserved its position with regard to the gas in storage component of Union's working capital. Later, in argument, Board Staff submitted that the forecast inventory requirements and the forecast working capital associated with gas in storage was reasonable.

2.1.7 The Board's Decision addresses the following items that relate to the Companies' 1996 and 1997 Capital Budgets and 1997 Rate Bases:

- capital budgeting process;

- system expansion - common policy for new distribution business;
- information technology;
- Union's Capital Budgets; and
- Centra's Capital Budgets.

2.1.8 The Board's overall findings on each Utility's Rate Base for 1997 can be found at the end of this Chapter.

2.1.9 The Board accepts the ADR Settlement Agreement on the issues of Centra/Union Best Practices Review and Union's Stress Corrosion Cracking Program Review, in which parties agreed to accept the Companies' evidence and proposals.

2.1.10 The Board notes that in the NEB MH-2-95 Report of November 1996 on the Public Inquiry Concerning Stress Corrosion Cracking of Canadian Oil and Gas Pipelines, the Summary includes the statement that:

"... the most effective method of addressing the issue of SCC would be through company-specific SCC management programs which require the systematic application to specific pipelines of the knowledge and best practices already developed across the industry."

2.1.11 Also the Summary of the Report recommends that:

"... the Board [NEB] require that SCC management programs contain three principal components:

a) determination of pipeline susceptibility to SCC and active monitoring of pipelines believed to be susceptible to SCC;
b) required mitigation if "significant" SCC is found and a clear identification of the criteria a company must consider in deciding among mitigation options; and
c) recording and sharing of information on susceptible pipelines."

2.1.12 The Board is concerned that the Companies' approach to SCC follows the best practices guidelines and recommendations in the MH-2-95 Report and directs the

Companies to bring forward more information on their SCC management programs in the next rates case. This information should include an estimate of the SCC-susceptible components of the Companies' pipeline systems.

2.2 CAPITAL BUDGETING PROCESS

2.2.1 The Companies provided evidence on their capital budgeting process. The need for capital expenditures arises in five basic areas: projects arising from special programs; work programs including items such as tools, equipment and vehicles; customer growth and system integrity; system replacement because of required relocations; and system replacement because of age, condition, obsolescence etc.

2.2.2 Individual capital requests are prepared by the responsible budget centre manager, and approved by a ratifier to ensure adherence to established engineering specifications and rules governing purchase standards, pricing and economic guidelines. Reviews as to the need, timing and economic justification of capital budget requests are carried out at successively higher levels of management The overall level of the budgets is reviewed with regard to the ability to finance the budgets.

2.2.3 A Capital Advisory Committee composed of senior managers from across the Companies reviews all major capital projects greater than $200,000. An Information Technology Steering Committee reviews the information technology expenditures. Recommendations from the committees are made to the Executive Planning Committee before the capital budget is finalized and presented to the Board of Directors for approval.

2.2.4 The Capital Advisory Committee's mandate is to ensure that the following criteria are addressed:

- the project provides value to the customer;
- customer rate impacts are considered;
- the project is consistent with the company's business plans and strategic goals;
- regulatory issues are identified and addressed; and
- economic justifications and business cases are accurate and complete.

2.2.5 The Board requested a witness panel from Centra to address the Board's concerns about the capital budgeting process that Centra had followed in setting its 1996 Capital Budget. The witnesses' evidence related to the Companies' capital budgeting process is summarized here, and the evidence related to Centra's 1996 and 1997 Capital Budgets is addressed in Section 2.6.

2.2.6 Centra's witnesses stated that as part of its review of capital budgets, its Executive took into consideration the impact on rates in the current year. The impacts were looked at from the perspective of the ratepayer and from the competitive position of natural gas with other energy forms. Impacts on future years were assessed in aggregate by examining five year forward forecasts of the overall revenue sufficiency or deficiency. The witnesses stated that no specific cap was set on what is an acceptable level of rate increase. The witnesses stated that the Company was starting to look more closely at the short-term rate impacts of the capital projects as part of the capital budget review process.

2.2.7 Centra's witnesses explained that the Company did not set an overall guideline on the total capital budget, but rather guidelines were provided on the factors that have to be addressed by management when bringing forward capital budget requests. In reviewing the capital budget, the Capital Advisory Committee examined the Company's ability to finance the budget, ensuring that the Company did not violate its short-term credit facility and recognizing the constraints imposed by its trust indentures and its ability to raise debt. The Committee does not explicitly prioritize projects, but projects are classified at a high level according to the strength of the business case.

Board Findings

2.2.8 Centra's last Board-approved Capital Budget was for the 1995 test year. At that time the Board approved a budget of $70.6 million. In fact, Centra spent $80.3 million on capital projects in 1995. Centra did not apply for a change in rates for 1996 and estimated its 1996 Capital Budget at $106.3 million. Centra's original proposed Capital Budget for 1997 was $81.4 million. The Board is concerned that these large increases in capital budgets will have a significant impact on customer rates.

2.2.9 The Board notes that in any capital budget, there are items that are revenue producing, items that are cost reducing and items that are required to meet safety and security of supply requirements. Some items are mandatory, but for some items a degree of discretion can be exercised with regard to the extent and timing of an investment. The Board also recognizes that the Company, as a monopoly provider of service, has a strong obligation to meet customer requests for service where they can be economically justified.

2.2.10 The Board is of the view that in setting the overall level of a capital budget Centra must take into consideration affordability criteria, including the ability of the Company to finance the projects, the ability to recover the costs from its customers and the customers' ability to pay these costs. In this connection, the Board believes that the impact of a capital budget on the rates of the Company is an important consideration, not only in relation to the competitive position of the Utility with regard to other competing energy forms, but also from the perspective of the ability of its ratepayers to pay the increased rates that may result.

2.2.11 The Board is encouraged by the statements of Centra's witnesses that the Capital Advisory Committee is beginning to look more closely at rate impacts associated with the Companies' capital budgets.

2.2.12 The Board also is of the view that in setting the overall level of a capital budget, consideration should be given to the timing of investments so that items that are discretionary can be spread out over a period of years, thereby avoiding rate shock on existing customers. Further, the Board expects the Executive to exercise its authority to prioritize project expenditures and adjust the overall level of capital budgets to mitigate rate impacts.

2.2.13 The Board recommends that the Companies' Executive establish ceilings for the level of capital budgets for Union and Centra separately. The Board is concerned that what may be affordable for Union's larger base of ratepayers may not be affordable for Centra's ratepayers.

2.3 SYSTEM EXPANSION - COMMON POLICY FOR NEW DISTRIBUTION BUSINESS

2.3.1 The Companies proposed to create a common set of guidelines for new distribution business applicable to both Companies. New distribution business is defined by the Companies as providing gas service to new customers who currently do not have access to natural gas. The Companies filed evidence describing each Company's policy.

2.3.2 Currently Union manages a single distribution business portfolio to maintain a rolling 12 month portfolio Profitability Index ("PI") above 1.0 and a positive Net Present Value ("NPV") of the portfolio at all times. Union applies the criterion of a minimum individual project PI of 0.8, including any customer contributions, and collects a market contribution from customers when a project fails to meet a Stage 1 economic criterion of a PI of 0.8. For residential customers the market contribution is set at $15 per month, for a maximum of 60 months, or until the project reaches a PI of 0.8. The $15 includes carrying costs. For large volume customers the policy is that the contribution will be calculated in proportion to their coincident peak day demand but, in no case shall it be less than the residential contribution. Once the market contribution payments result in the project PI reaching 0.8, the monthly collections from customers cease. If, after the forecast period, the project PI is not reached, the shortfall is to the account of the shareholder.

2.3.3 Centra manages its system expansion portfolio on a fiscal year basis using two capital pools. The first pool, U-1, comprises all distribution projects other than those that require specific prior Board approval. The U-1 pool is managed to a NPV of greater than zero. The second pool, U-4, consists of projects that require prior Board approval. Centra manages the U-1 and U-4 pools to avoid undue rate impacts. Centra applies a minimum project PI of 0.8 including customer contributions. For Centra the market contribution is collected for a period of 60 months from the time the customer connects to the system. Centra has not developed a market contribution policy for large volume customers, but intends to apply Union's guidelines.

2.3.4 Currently both Union and Centra customers may pay their market contribution as a lump sum payment up front instead of a monthly contribution. Also, if a customer moves or sells the property, the balance of the contribution becomes due, unless the buyer signs an agreement to assume the financial obligations of the remaining payments.

2.3.5 For both Union and Centra, projects for the exclusive use of individual industrial accounts must achieve a PI of 1.0, or a contribution in aid to construct must be collected to bring the project to a PI of 1.0.

2.3.6 The Companies proposed to merge their new distribution business guidelines to create a single set effective January 1997, by adopting Union's policy and accounting treatment for customer contributions and using Union's 12 month rolling portfolio PI, as opposed to Centra's fiscal year portfolio.

2.3.7 The Companies sought Board endorsement to "manage overall expansion activity to a level that means existing customers are not unduly impacted by the addition of new customers". The Companies proposed to maintain a rolling portfolio PI of 1.0 but to remove the individual project profitability thresholds.

2.3.8 The Companies also proposed to identify separately in their rate filings only projects with a capital cost exceeding $500,000. Centra historically had used a $200,000 threshold.

ADR Settlement Agreement

2.3.9 The following parties participated in the discussion of this issue: Kitchener, Schools, NOVA, ONA, Board Staff, CAC, ECNG, Energy Probe, NRG, IGUA, OCAP, Pollution Probe and GEC.

2.3.10 In the ADR Settlement Agreement the parties agreed that the Companies should continue to operate under their existing new distribution business policies, namely to maintain a rolling PI of 1.0 and to ensure that individual projects have a PI of at least 0.8, until the Board has made a final decision in the E.B.O. 188 proceeding on matters related to natural gas system expansion. The parties also agreed that, in the interim, the Companies would maintain the status quo with respect to market contribution charges.

2.3.11 The parties further agreed to defer to the E.B.O. 188 proceeding, or failing resolution in that case, to the next rates case, the question of what are the appropriate objective criteria that should be applied to assess projects that are justified on the basis of safety, security of supply or system integrity. The ADR Settlement Agreement stated this reflected the Companies' confirmation that the PI for all distribution projects would be maintained above 1.0 after other transmission reinforcement projects were included in the calculation.

2.3.12 Further, the Companies agreed to provide the results of applying the Societal Cost Test to distribution new business projects as directed in the Board's E.B.O. 188 Interim Report, as soon as these results become available. The parties also agreed that Centra would continue to provide details on capital budget items in excess of $200,000.

Board Findings

2.3.13 The Board accepts the Companies' position, as reflected in the ADR Settlement Agreement, that they will continue to operate within their existing natural gas system expansion policies until a final decision is available from the E.B.O. 188 proceeding.

2.3.14 The Board notes and accepts Centra's commitment to continue to file details of capital budget items in excess of $200,000.

2.3.15 The Board advises the Companies that rate impacts will be considered by the Board when assessing the inclusion of capital expenditures in rate base for a test year and, therefore, each of the Companies should take rate impact into consideration when establishing the level of their overall capital budget and system expansion program. In this regard, the Board notes its observation in the E.B.O. 188 Interim Report that:

> *The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0, the impact on rates in a given year may be undue. For this reason, the Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue rate burden on existing rate payers.* (paragraph 4.5.10)

The Board would also welcome innovative ideas from the Companies on how such rate impacts could be mitigated.

2.3.16 The Board also notes that the Companies have not as yet provided the results of applying the Societal Cost Test to distribution new business projects and expects the Companies to file these with the Board when they become available. The Board wishes to remind parties that it specified, in its E.B.O. 188 Interim Decision, that for new distribution business, the Societal Cost Test would be applied at the portfolio level and not at the project level.

2.4 INFORMATION TECHNOLOGY

2.4.1 Union and Centra identified the driving forces behind their information technology ("IT") initiatives as the requirement to:

- respond to customer demands for new and more cost-effective services;
- take advantage of efficiencies offered by new information technology development; and
- meet the increasing information exchange and reporting requirements with suppliers, associated businesses, governments, industry associations and others.

2.4.2 The Companies described their objectives for the use of information technology as:

- to facilitate customer service by providing timely and consistent information;
- to improve and maintain employee productivity; and
- to anticipate and integrate new technology to improve customer service.

2.4.3 The Companies stated that as a result of their Shared Services initiative, a combined process for both companies had been introduced for the management of the IT expenditures. This process included the establishment of an Information Technology Steering Committee which would review and rank all IT projects and monitor the progress on approved projects. Business cases are required for each major IT project and all major projects are subject to the Companies' capital budgeting process.

2.4.4 The Companies reported that as a result of the Shared Services initiative, benefits had been achieved through:

- consolidation of the data centre facilities of the two Companies into one centre allowing the use of one set of software, one method of data storage, the sharing of one mainframe computer and the use of one computer job-scheduling system;
- reduction of the capacity of the mainframe computer as a result of the shift to smaller distributed network computers; and
- reduction in IT department staffing levels.

2.4.5 Table 2.2 summarizes the Companies planned capital expenditures on IT in 1996 and 1997. Actual 1995 expenditures are shown for comparison purposes only.

Table 2.2: Continuity Statement of IT Capital Expenditures 1995-1997

	1995 Actual	**1996 Estimated**	**1997 Forecast**
		($000)	
UNION IT CAPITAL SPENDING			
Business Information System	1,052	6,990	0
Automated Mapping	5,668	6,248	5,770
In-truck Terminal Replacement	36	2,000	2,250
End-use Metering	15	844	378
ITE Project (1)	7,050	7,200	5,835
Other Expenditures	3,097	2,718	1,765
TOTAL	**16,918**	**26,000**	**15,998**
CENTRA IT CAPITAL SPENDING			
Business Information System	1,225	1,600	0
Automated Mapping	329	2,915	3,056
ITE Project (1)	1,589	4,799	3,890
Other Expenditures	801	1,338	0
TOTAL	**3,944**	**10,652**	**6,946**
Footnote (1) Information Technology Environment ("ITE")			

BIS Project

2.4.6 The Business Information System ("BIS") project was initiated in 1995 for Union and Centra to provide a single combined financial system for: management reporting and profitability analysis; financial accounting; accounts payable reports; budgeting for operating and capital expenditures; materials management and asset management. The BIS project was expected to be completed by January 1997. The budgeted cost of the project at the time of the Shared Services hearing (E.B.O. 177-06/E.B.R.L.G. 34-12) was $6.2 million. The current revised cost estimate is $10.9 million. The Companies claimed that the increase in costs resulted from a more detailed understanding of the scope of the project. The costs have been allocated between the two Companies in the same proportion as the Finance department's composite ratio for net operating and maintenance ("O&M") expenses, which is 74% to Union and 26% to Centra.

AM Projects

2.4.7 Union initiated its automated mapping ("AM") and facilities management ("FM") project in 1994. As a result of the Board's direction in E.B.R.O. 486, Union separated the automated mapping component from the facilities management component. The Companies stated that they had delayed the FM component to give priority to completing the AM system at Centra.

2.4.8 The Companies advised that Union, for its AM project, had been able to obtain 50% of its digital land information base from the Ontario Government's Polaris project which digitizes the base maps of municipalities.

2.4.9 The current estimate of the total project cost to the end of 1998 for Union's AM project is $25.8 million of which $13.1 million had been spent up to the end of 1995. Union's proposed capital budget for 1996 and 1997 for the AM project includes expenditures for its Hamilton, Halton, Brantford and Waterloo divisions.

2.4.10 Centra retained a consultant in May 1995 to evaluate the costs and benefits of an AM/FM system using the Union system and indicated that the consultant's study showed cumulative quantified benefits of $16.5 million over a fifteen year period, with annual quantified savings of $1.6 to $6.5 million. Centra conducted its own analysis of the benefits and costs of adopting Union's AM system which demonstrated a PI of 1.28. Centra also retained a contractor to begin a Thunder Bay pilot project ("the Thunder Bay Project") in November 1995 which was expected to be completed by June 1996. Centra stated in E.B.R.O. 489 that upon completion of the Thunder Bay Project, it would "confirm that the system design was appropriate and that project implementation costs were in line with budget estimates". Centra claimed that the benefits of the AM project to Centra would be more immediate than at Union, because of the poor state of Centra's existing records and the ability to make use of the software and system development at Union.

2.4.11 Centra advised that it had not been able to obtain the Polaris land base data for any of its required mapping. Centra indicated that while it had held discussions with Ontario Hydro and Bell Canada to coordinate their mapping activities, no formal arrangements had been put in place.

2.4.12 Centra included in its Capital Budget, $8.058 million spread over 1995 - 1998 to implement an AM system project. These expenditures are to cover the conversion of Centra's facility maps and as-built records, as well as software/hardware and training for field personnel.

ITE Project

2.4.13 The ITE project expenditures relate to the annual spending to replace, upgrade or enhance the computing environment and include personal computers, large computers, data storage facilities, telecommunications network, system management tools, electronic-mail system and support process.

2.4.14 The purchase of personal computers represented the largest category of hardware and software expenses in 1996 and 1997. In response to a request from the Board, the Companies indicated that they planned to convert (either replace or upgrade) approximately 2,100 personal computers and work station units over 1996 and 1997 at an average per unit cost of $5,700 including hardware, software and installation.

2.4.15 The allocation of the ITE project budget between Union and Centra was based on "the number of personal computers implemented in each Company in 1996 and 1997." The resultant split was 40% to Centra and 60% to Union. The remainder of the ITE project costs were allocated in the same proportions. The ITE project capital budget for 1996 and 1997 for Union totals $13.0 million. For Centra the ITE project capital budget for 1996 and 1997 totals $8.7 million of which $7.2 million is for expenditures on personal computers ("PCs") and local area networks ("LANs").

CIS Project

2.4.16 The Companies' original filing included planned capital expenditures over the 1996 to 1998 period for the development of a Customer Information System ("CIS"). The Companies planned to develop this system in conjunction with other affiliated Westcoast companies. Planned expenditures for Union totalled $17.3 million and for Centra a total of $5.6 million, which represented the share of the development costs allocated by Westcoast to the Companies. The Companies claimed that through joint development of the system and sharing the costs with the other Westcoast companies, they would be able to achieve significant savings.

2.4.17 The Companies subsequently amended their proposed 1997 Capital Budgets, 1997 Rate Bases and O&M costs to remove the capital and operating expenses associated with the development of the CIS. The Companies stated that "because of the joint nature of the project and the potential for providing CIS services to third parties in the future, it has been decided that the CIS should ultimately be provided to Union, Centra and the other Westcoast distribution companies through an affiliated company within the Westcoast group".

ADR Settlement Agreement on Information Technology

2.4.18 The following parties participated in the discussion of this issue: Kitchener, Schools, NOVA, ONA, Board Staff, CAC, ECNG, HVAC, NRG, IGUA, and OCAP.

2.4.19 Other than NOVA, and IGUA who reserved the right in argument to support NOVA, the parties that participated in the discussion of this issue reached the following agreements.

2.4.20 The parties agreed to reduce the joint capital budget for all IT expenditures in 1997 by $2.082 million. This agreement was based on the recognition that the reduction would maintain expenditures at 1995 levels. The parties agreed that reductions should be apportioned 62.7% to Union and 37.3% to Centra to reflect the proportionate split of the total shared asset capital budget.

2.4.21 The parties agreed to reduce the 1997 Rate Base attributable to the joint BIS project by $1.1 million. The parties stated that the reduction reflects the fact that there have been increases in BIS expenditures from those forecast during the Shared Services proceeding, but also reflects the fact that the forecasts given in the Shared Services proceeding were preliminary estimates. The parties further agreed that this reduction in rate base should be apportioned 74% to Union, and 26% to Centra.

2.4.22 The Companies undertook to include in future filings, detailed IT budget projections, including O&M, capitalized program costs and projected program cost to completion. Each project with a projected in-service cost greater than $1 million would be justified by a cost/benefit analysis. The analysis would address which functions at the Utilities will benefit from IT investment (eg Rental Program or Gas Supply).

2.4.23 The ADR Agreement on the CIS stated as follows:

> *Centra/Union originally proposed to acquire and modify a CIS system to replace Centra's CIS-1 and Union's CICS. Centra/Union filed updated evidence respecting a change whereby an affiliated company within the Westcoast group would acquire and modify a CIS system and provide service to Centra, Union and other Westcoast LDCs. The Companies are not currently seeking any recovery in rates respecting CIS services that may be provided by an affiliate. It was acknowledged that any cost associated with the Companies' decision to buy the CIS service from an affiliate would not be recoverable in rates until a public hearing is held to deal with affiliate transaction approval and the Companies' proposal to purchase the CIS service from an affiliate has been approved by the Board as an affiliate transaction. Concerns were expressed about the lack of evidence in this case justifying the decision to buy CIS from an affiliate. The Companies contend that there is no need for them to justify this decision in this case. Some parties were concerned that the failure to scrutinize the Companies' decision to purchase CIS services from an affiliate in this rates case may prejudice their position when the Companies apply for affiliate transaction approval in the future. The Companies acknowledge that there is no*

intent to limit parties rights to scrutinize the affiliate transaction in the future outside of this current proceeding. The Companies agreed that at the time they apply for Board approval of the affiliate transaction to purchase a service from its affiliate respecting CIS services, they will: (a) request a public review of the proposed transaction; (b) file evidence justifying the proposed fees including an accounting of services provided by Centra/Union to develop the system and an accounting of any benefits provided by Theseus or CIS-1 incorporated into the CIS and (c) file comparative information between any service contract, costs and fees to those incurred by other utilities.

Positions of the Parties

2.4.24 OCAP submitted that if an affiliate develops the CIS system, the Board must be able to scrutinize costs when they are incurred by the separate organization. OCAP stated that it reserved its submissions on the subject of CIS in light of the Companies' undertakings, given in response to an ADR Settlement Agreement clarification request from the Board, to seek affiliate transaction approval prior to any CIS services being provided by Westcoast. OCAP noted its expectation that the Board will not approve any CIS-related affiliate transactions without a hearing, or at a minimum receiving submissions from interested parties.

2.4.25 NOVA questioned the level of capital spending on the ITE project, noting that when the total spending of some $29 million over the 1995 to 1997 period was divided by the number of employees, 3,300, the expenditure per employee exceeded $8,500. NOVA imputed from the date of the business case for the project that spending on the project commenced well in advance of the justification for the project, and commented that the business case contained no description of any benefits from the ITE project.

2.4.26 NOVA argued that the written record provided by the Companies was insufficient and that NOVA had not requested a witness panel because to do so would only have provided the Utilities with an opportunity to augment a deficient record. In view of the fact that Union had not provided evidence on the benefits that would justify the ITE capital expenditures, NOVA submitted that the Board might wish to apply a "reality discount" of 25% to the estimated 1996 and 1997 capital expenditures for the purpose of addition to rate base, in addition to the adjustments agreed to by the participants in the ADR Settlement Agreement.

2.4.27 NOVA requested that the Board comment on the lack of cost/benefit information and define the type of information it will require from Union in support of the purchase of a CIS. NOVA submitted that Union should understand it must discharge a considerable onus to persuade the ratepayers that the CIS, or any other new technology is appropriate and represents value for money.

2.4.28 IGUA supported NOVA's submissions.

2.4.29 The Companies, in reply, submitted that there is no basis in the evidence to support NOVA's contention that the information technology capital expenditures in 1996 and 1997 should be reduced by 25%. Further, the Companies noted that their current proposal is to purchase CIS services, not the CIS system itself, and that the ADR Settlement Agreement specifically outlines filing commitments for the next rates case respecting IT expenditures, as well as the information that will be filed to support any affiliate CIS services.

2.4.30 The Companies further submitted that the concerns raised by OCAP have been addressed by their commitment to seek affiliate transaction approval prior to any CIS services being provided.

Board Findings

IT Capital Budget

2.4.31 The Board accepts the reduction of $2.082 million, as agreed to in the ADR Settlement Agreement, in the joint capital budget for IT projects. The Board accepts the proposed allocation of 62.7% to Union and 37.3% to Centra, as this reflects the proportionate split of the total shared asset capital budget. The Board observes that the parties to the ADR Settlement Agreement drew comfort from the fact that, after the reduction negotiated in the Agreement, the overall level of IT capital expenditures in 1997 for the Companies was at the 1995 level. However the Board notes that the resulting 1997 IT capital budget for Centra is still some 56% higher than the 1995 level of expenditures. The resulting 1997 IT capital budget for Union is some 13% lower than the 1995 level of actual expenditures. The Board is of the view that the level of Centra's IT capital expenditures is still cause for concern, and will address the matter in its specific findings later on in this Chapter.

2.4.32 The impact on gross plant of Centra's 37.3% portion of the $2.082 million reduction in IT capital expenditures in 1997 is $417,000 based on a uniform reduction of these expenditures throughout the year. No adjustment has been made to depreciation expense or accumulated depreciation as the opening asset balance is unaffected. The impact on Centra's capital cost allowance is discussed under the heading Centra's 1996 and 1997 Capital Budgets.

2.4.33 The impact on Union's gross plant is $661,000 and, as Union determines depreciation based on assets brought into service in the fiscal year, accumulated depreciation has been reduced by $55,000 to reflect Union's portion of the IT capital budget adjustment. The impact of the reduction in IT capital expenditures on Union's depreciation expense and capital cost allowance is included in the reductions discussed under the heading Union's 1996 and 1997 Capital Budget.

2.4.34 While the Board makes a number of findings and adjustments to Centra's Rate Base relating to the Companies' joint IT capital budget, the Board is not persuaded by the evidence that it should follow the suggestion of NOVA to apply a further overall reduction to the Companies' joint IT capital budget, beyond those agreed to in the ADR Settlement Agreement.

BIS Project

2.4.35 The Board accepts the reduction of $1.1 million in Rate Base in 1997 to mitigate the increased costs of the BIS Project as agreed to in the ADR Settlement Agreement. The Board agrees with the parties that there is a balance between the escalation in costs of the BIS Project since the joint Shared Services hearing and the preliminary nature of the estimates of the costs of the project provided at that hearing. The Board accepts the allocation of this reduction between Centra and Union as agreed to by the parties, namely 74% to Union and 26% to Centra.

2.4.36 The impact on gross plant of Centra’s 26% portion of the BIS Project-related Rate Base reduction is $310,000, while Union’s gross plant is reduced by $886,000. The impact of this reduction on the opening asset balance results in a reduction of $48,000 in Centra’s depreciation expense and $24,000 in accumulated depreciation. The impact on Centra's capital cost allowance is discussed under the heading Centra's 1996 and 1997 Capital Budgets. The impact of the BIS Project reduction on Union’s depreciation expense and capital cost allowance is included in the reductions discussed under the heading Union’s 1996 and 1997 Capital Budgets, while accumulated depreciation has been reduced by $74,000.

AM Projects

2.4.37 The Board notes that in E.B.R.O. 489, Centra proposed an expenditure of $600,000 in 1995 to acquire an AM/FM System which would allow Centra to use digitized maps and facility information to plan, design, maintain and update underground facilities. Centra proposed that it would begin digitizing its records in the Thunder Bay service area and use the experience gained to determine the feasibility of proceeding with AM/FM on a broader basis.

2.4.38 In its E.B.R.O. 489 Decision with Reasons - Part II, the Board approved the AM/FM expenses "specifically for the purpose as proposed by Centra." The Board stated "should Centra wish to further develop the application of AM/FM, the Board expects that Centra will bring this matter to the Board".

2.4.39 Centra's evidence in this proceeding was that it had engaged a consultant in May 1995 to evaluate the benefits of utilizing Union's AM/FM system. After a favourable report from the consultant, Centra commenced the Thunder Bay project in November 1995. The project was expected to be completed in June 1996 at a cost of $700,000, at which time Centra would confirm that the system design was appropriate and that the project implementation costs were in line with the estimates.

2.4.40 In this proceeding, Centra requested approval for $2.915 million in capital expenditures for 1996 and $3.056 million in 1997 for the AM component of its AM/FM project. However, Centra did not file the 1995 Consultant's report nor did it file its analysis of the completed Thunder Bay project. It did file extracts from the cost/benefit section of the Consultants' report in response to a request from the Board.

2.4.41 The Board notes that it was Centra's evidence in E.B.R.O. 489, that it would evaluate the Thunder Bay project before proceeding further with the AM project and the Board made it clear in its E.B.R.O. 489 Decision - Part II that it expected Centra to bring this matter to the Board if Centra wished to further develop the AM project. In spite of this Centra apparently will have spent $2.9 million in 1996 on the AM project.

2.4.42 The Board has not received any evaluation of the Thunder Bay Project, nor has it been given any analysis of the financial transaction between Union and Centra resulting from Centra's use of Union's AM/FM system. In its E.B.O.177-06/ E.B.R.L.G. 34-12 Decision on Shared Services the Board granted Union and Centra an exemption from their respective affiliate transactions in respect of the sharing of management information systems. However, the Board directed the Utilities to closely monitor the sharing of personnel and facilities in order to ensure that there is no cross-subsidization between each Utility's distribution operations and the storage and transportation operations.

2.4.43 The Board is not satisfied that further expenditures on the AM Project have been sufficiently justified. The Board therefore finds that $2.915 million should be removed from Centra's 1996 Capital Budget and $3.056 million from Centra's 1997 Capital Budget and excludes these amounts from Centra's 1997 Rate Base for the purpose of determining 1997 rates. The Board notes that in E.B.R.O. 489 it approved an amount of $600,000 in the 1995 Capital Budget for the Thunder Bay Project. The Board notes that the Company's actual spending in 1995 was $329,000. The Board is prepared to allow a further $400,000 into Rate Base for completion of the project. Should Centra have a sound business case for further expenditures on the AM Project it can always present it to the Board and seek approval for the above expenditures. The Board also expects Centra to file a report on the Thunder Bay Project.

2.4.44 The Board encourages Centra to continue discussions on cooperation with other agencies for the development of digitized maps for the Centra franchise area with a view to achieving cost savings in the implementation of the AM Project.

2.4.45 The Board has reduced the 1997 Rate Base by the full $2.915 million for the 1996 Capital Budget associated with the AM Project, less the $400,000 required to complete the Thunder Bay Project. As these adjustments impact the opening asset balance upon which depreciation expense is determined, the Board has made a corresponding reduction of $419,000 to depreciation expense, and a corresponding reduction of $210,000 to accumulated depreciation. The Board has determined that a reduction to Centra's 1997 capital cost allowance of $875,000, less $60,000 resulting from the approval of the remaining cost to complete the Thunder Bay Project, is required. The reduction of $3.056 million in Centra's 1997 Capital Budget results in a $1.525 million reduction to gross plant, based on an average of monthly averages. The Board has determined that the capital cost allowance shall be reduced by $458,000 in this regard.

ITE Project

2.4.46 The Board is concerned about what appears to it to be an unreasonably high level of expenditures on the ITE Project by Centra.

2.4.47 While the Board has accepted the reductions negotiated by the parties to the ADR settlement process in the IT budgets of Centra and Union, the Board remains concerned about the growth in Centra's ITE Project capital expenditures.

2.4.48 The Board notes that using the 60:40 (Union/Centra) ratio employed by the Companies for apportioning the ITE Project capital expenditures between Centra and Union, it would appear that of the total 2,100 personal computer replacements or upgrades approximately 840 units would be allocated to Centra. The Board also notes that the Companies use an overall head count ratio of 78:22 (Union/Centra) as a cost driver for the allocation of O&M costs. Applying this ratio to the Companies' overall head count in 1997 of 3,329 implies some 732 full time equivalents ("FTEs") at Centra. The Companies estimated the average cost of replacement/conversion of terminal work stations with PCs at $5,700 per unit.

2.4.49 The Board finds the overall budget for PCs to be excessive. The Board therefore reduces the allowed ITE capital budget for Centra for 1997 by an additional $570,000 which is approximately the cost of 100 personal computers. The Board has assumed a uniform reduction of these expenditures throughout 1997, and has consequently reduced Rate Base by $285,000, based on an average of monthly averages. The Board has also reduced the 1997 forecast capital cost allowance by $86,000 as a result of this finding.

CIS Project

2.4.50 The Board confirms the requirement, committed to by the Companies, that they "will seek affiliate transaction approval from the Board under the relevant Undertakings of Union and Centra prior to any CIS services being provided to Union or Centra by Westcoast".

2.4.51 The Board is of the view that, while the future filing commitments set out in the ADR Settlement Agreement will provide useful information, these commitments are insufficient. The Board has not been presented with a formal detailed quantified business case which justifies the need for the planned CIS expenditure, options for providing these services, including the choice to outsource for these services, variations on the scale and scope of these options, and a risk analysis of these options involving an assessment of technological, financial and regulatory risk. The Board directs the Companies to provide this information, in addition to that agreed to in the ADR Settlement Agreement, at the time of the application for an affiliate transaction approval.

2.4.52 The Board has experienced several problems in the past related to implementation of new rates as a result of restrictions in the Companies' billing systems. These include the inability of the billing system to accommodate a series of monthly charges. The Board expects that any new systems would remedy such problems.

2.5 UNION'S 1996 AND 1997 CAPITAL BUDGETS

2.5.1 Union's Capital Budgets for 1996 and 1997 are summarized in Table 2.3. The 1995 budget is shown for comparison purposes only, however, the figures are not directly comparable with those for 1996 and 1997 because they represent only a nine month period from April to December 1995 due to the change to a calendar year fiscal year for Union as of December 31, 1995.

Table 2.3: Continuity Statement of Union's Capital Budget

Capital Budget ($ millions)				
	1995 Board Approved [1]	1995 Actual [1]	1996 Estimated	1997 Forecast
Storage	4.840	5.116	3.784	28.148
Transmission	32.541	41.317	41.227	26.288
Distribution	73.760	72.793	60.258	65.352
General Plant	64.718	50.585	76.614	62.010
Other	23.272	26.494	27.847	26.773
TOTAL	**199.131**	**196.305**	**209.730**	**208.571**

[1] For 1995 - 9 month period only

2.5.2 The main *storage* projects included in Union's 1997 Capital Budget were related to the Dawn Station Integrity Program and the Bentpath/Rosedale (Storage) Project. The Capital Budget included $25.7 million for the Bentpath/Rosedale (Storage) Project. The Board approved this Project in November 1996 (E.B.L.O. 257/E.B.R.M. 107).

2.5.3 Union's *Distribution* capital budget includes distribution new business, mains replacement due to leakage and municipal roadwork, replacement meters, regulators and services. Union originally proposed a distribution new business capital budget for 1997 of $50.9 million to supply a forecast 24,403 customer additions with a resulting overall cumulative net present value of $7.8 million and PI of 1.15. Union initially included four projects with capital costs over $500,000 in its budget: Howard Township, Mitchell's Bay, Port Elgin and Wiarton. Union deferred the projected completion of the Wiarton project to 1998 and excluded those capital costs from its proposed budget. The Company subsequently updated its proposed distribution new business capital budget for 1997 to $46.6 million to supply a forecast 22,453 customers.

2.5.4 Union's distribution new business capital budget for 1996 was $40.5 million to attach a forecast 23,357 new customers with a resulting overall net present value of $16 million and PI of 1.39.

2.5.5 Union's 1996 *Transmission* capital budget included $25.7 million for the construction of 18.1 km of NPS 48 pipeline from Bright to Owen Sound. It stated that if this project were approved, it would require no additional facilities on the Dawn-Trafalgar System in 1997. The Board issued its approval of this project application in July 1996 (E.B.L.O. 251 [Addendum to Decision with Reasons]). Union's proposed transmission capital budget for 1997 included additional compression at the Parkway Compression Station, expenditures for the Dawn-Trafalgar System Integrity Program and certain other facilities to meet new business growth and system reliability. In its initial filing Union also included a project for reinforcement of the Owen Sound Line System, but this was deferred because of revised throughput forecasts and deferral of the Wiarton distribution new business project.

2.5.6 Union's *General Plant* project category includes expenditures for furniture and office equipment, computer equipment, tools and work equipment, transportation and heavy work equipment and buildings. In its proposed 1997 Capital Budget for the General Plant project category Union included: $36 million for rental/leased equipment, primarily water heaters; $1.1 million for its natural gas vehicle ("NGV") program; $4.8 million for vehicle replacement; and $16 million for IT expenditures.

2.5.7 The *Other* category of the 1997 Capital Budget includes an amount of $26.8 million related to capitalization of general overhead expenditures applicable to capital projects.

2.5.8 Union also filed information related to variances between the 1995 approved Capital Budget and actual costs for 1995 project expenditures. This indicated a variance of $1.528 million between the actual costs of $7.794 million for the Brantford Service Centre and the Board approved costs of $6.266 million. Union stated that the major part of this difference resulted from the fact that the old service centre has not yet been sold.

2.5.9 Union filed post construction reports noting the variances in costs between the actual construction costs and the budget estimates presented to the Board for the following projects:

! Edy's Mills	+9.7% (actual exceeds estimate)
! Milton to Parkway	+58%
! Lobo to St. Marys	+8%
! St.Marys to Beachville	-10% (estimate exceeds actual)
! West Windsor Cogeneration Line	-40%

2.5.10 The largest cost increase was on the Milton to Parkway Tie-In Station which was constructed in 1991. The major portion of the $14.6 million increase over the estimated $25 million cost of the project was attributed to increased land, easement and damages costs. These costs were $10.5 million or 219% higher than estimated. Union's explanation was that the increase resulted from high land values in Milton, land owners exercising the option to sell rather than lease their land and higher than estimated commercial and specialty crop damages on the construction route.

ADR Settlement Agreement

2.5.11 Parties that participated in the discussion of issues related to aspects of Union's Capital Budgets were: Kitchener, NOVA, ONA, Board Staff, CAC, ECNG, Energy Probe, NRG, IGUA, OCAP, Universities, Schools, and Consumers' Gas. Not all parties participated in discussion of all issues: for example, Consumers' Gas participated only in discussions of those issues related to storage.

2.5.12 The parties agreed to Union's 1997 Capital Budget proposals with the adjustments described below. All parties reserved their right to review the inclusion of any expenditures currently in the Construction Work In Progress ("CWIP") account when Union proposes to transfer those expenditures from CWIP into rate base.

2.5.13 As part of the ADR Settlement Agreement Union agreed to:

- ! reduce the 1997 Capital Budget associated with the Dawn Lightning Protection project from $200,000 to $50,000. This reduction reflects changes in the scope of the work involved and results in a reduction of $88,000 to gross plant, and $1,000 to accumulated depreciation based on the average of monthly averages;

- ! reduce expenditures for mains replacement due to leakage and to municipal road work in 1996 by $843,000. This change will maintain Union's budget at the level approved by the Board for 1995, recognizes Union's actual spending to date for 1996 and recognizes municipal spending restraints which limit these expenditures. This adjustment results in a reduction of $843,000 to gross plant and $11,000 to accumulated depreciation based on the average of monthly averages;

- ! reduce its 1997 Rate Base to reflect a reduction in the number of Vehicle Refuelling Appliances ("VRAs") installed for the NGV program from 92 to 15 in 1996 and from 52 to 16 in 1997, in accordance with actual expenditures in prior years. These reductions result in a $293,000 reduction in the 1996 Capital Budget and a $140,000 reduction in the 1997 Capital Budget. Gross plant has been reduced by the full $293,000 removed from the 1996 Capital Budget, and by a further $71,000 for the 1997 Capital Budget based on an average of monthly averages, for a total gross plant reduction of $364,000. Accumulated depreciation has been reduced by $10,000 as a result of these capital budget reductions;

- ! reduce the 1997 budget for office furniture from $585,000 to $300,000. This change maintains these expenditures at approximately the same level as in 1995 and results in a reduction of $144,000 to gross plant and $4,000 to accumulated depreciation based on the average of monthly averages; and

- ! defer the in-service date for the Port Elgin distribution expansion project from December 1997 to January 1998 based on the latest construction schedule. The one month deferral results in a reduction of $311,000 to gross plant and $52,000 to accumulated depreciation. There will be no change to forecast customer attachments or revenues in 1997 as a result of this deferral, because the impact of the deferral on these other items is not material.

2.5.14 The combined impact of the above adjustments, along with the adjustments related to Union's portion of IT capital expenditure reductions and the BIS Project reduction has resulted in a reduction of $410,000 to depreciation expense and $768,000 to capital cost allowance as noted in the financial statements supporting the ADR Settlement Agreement.

2.5.15 The Company agreed that all of the above noted 1996 and 1997 Capital Budget reductions will be reflected in the forecast 1997 Rate Base.

2.5.16 The ADR Settlement Agreement also recognized Union's updated evidence that the proposed in-service date for the Parkway Compressor Station addition has been deferred by one year to 1998. Union agreed to prefile evidence dealing specifically with this project in its next rates case and to justify expenditures on this project at that time.

2.5.17 Parties to the ADR Settlement Agreement accepted the explanations for the cost overruns related to the Brantford Service Centre. Union expected to offset the overrun by $725,000 as a result of the proceeds from the sale of the old service centre and committed to report on the status of this sale in the next rates case.

2.5.18 The parties to the ADR Settlement Agreement agreed that Union's evidence and proposals in connection with proposed gas storage facilities should be accepted.

Board Findings

2.5.19 The Board requested further information regarding the cost overrun of the Brantford Service Centre and the accounting treatment of these costs. In light of the information provided by Union, the Board accepts Union's accounting treatment of the Brantford Service Centre.

2.5.20 The Board notes that there were significant variances shown in the post construction financial reports filed by Union. The Board directs the Company to work with Board Staff to design a process which will lead to more timely review of such variances. In addition the Board expects in future ADR Settlement Agreements parties will address major variances in post construction financial reports.

2.5.21 The Board further notes that the capitalization of O&M and Administrative and General ("A&G") Expenses are done on a percentage basis, based on the forecast cost of the project. These capitalized costs are removed from the expenses upon which the Board determines the Company's revenue requirement and establishes rates. In situations of project cost overruns, the actual capitalized expenses may be greater than the forecast expenses. The Board is concerned that this may enable the Company to recover the difference between the forecast and actual O&M and A&G capitalized expenses twice - once in the approved rates for the test year, and once in future rates as these costs are capitalized and expensed in future years. The Board expects the Companies in their next rates hearing to provide evidence that addresses this concern.

2.5.22 The Board notes and accepts the adjustments agreed to in the ADR Settlement Agreement to Union's 1996 and 1997 Capital Budgets and finds that Union's Rate Base for the test year should be adjusted accordingly.

2.6 CENTRA'S 1996 AND 1997 CAPITAL BUDGETS

2.6.1 Centra's Capital Budgets for 1996 and 1997 and a comparison with 1995 are summarized in Table 2.4 below.

Table 2.4: Continuity Statement of Centra's Capital Budget

Capital Budget ($ million)				
	1995 Board Approved	**1995 Actual**	**1996 Estimated**	**1997 Forecast**
U-1 New Business	37.528	48.808	48.371	39.273
U-2 System Betterment	10.110	11.819	11.993	13.229
U-3 Gas Storage etc.	0	0	0	0.538
U-4 Expansion	0	0.132	7.697	1.465
U-5 General Plant	9.151	6.697	22.263	11.125
U-6 Administration	12.263	13.944	13.902	14.040
U-7 Net Proceeds	0.539	0.651	0.534	(0.067)
U-8 Contributions	(0.392)	(0.449)	(0.234)	(0.286)
U-9 Capital Leases	1.402	1.702	1.747	2.057
TOTAL	**70.601**	**83.304**	**106.273**	**81.374**

2.6.2 As previously discussed, Centra's system expansion capital budget is in two parts: the U-1 category covers communities that Centra already serves and the U-4 category includes those that it does not currently serve. U-1 also includes Centra's budget for capital expenditures on rental equipment for new customers and on its NGV program.

2.6.3 Centra's 1997 Capital Budget includes $25.6 million in the U-1 category to supply a forecast 8,886 new customers with a projected overall NPV of $9.4 million and a PI of 1.37. Centra included four projects with first year capital requirements over $500,000 in this category: Garden River Reserve, Port Sydney, Berwick/Crysler, and West Lake. All these projects had forecast PIs in excess of 0.8 with only Berwick/Crysler requiring a market contribution. Centra's 1997 U-4 budget represents the costs of extending service to the community of South Mountain which Centra stated had a PI of 0.81 after market contribution.

2.6.4 Centra's 1996 Capital Budget included $35.4 million in the U-1 category for attaching 8,884 new customers. Centra included four projects in this category which had first year capital requirements in excess of $500,000: Morewood, Temagami, Cumberland Beach and Wooler. Centra's prefiled evidence showed that these projects had PIs of 0.8 without market contribution.

2.6.5 The 1996 U-4 budget includes the costs of extending service to the communities of Tweed, Marmora/Deloro, Harris Township (Dawson Point), Cache Bay and Finch. Centra stated that these projects had PIs of 0.8 after market contribution.

2.6.6 Centra's U-2 category for system betterment represents capital expenditures for improving the gas distribution system and also includes capital expenditures on rental equipment to replace older and defective equipment on existing customers' premises.

2.6.7 Centra's total capital budget for both the U-1 and U-2 categories for rental equipment was $19.6 million in 1997 and $18.5 million in 1996. Centra stated that the return on rate base for the combined U-1/U-2 rental program would be 10.95% in 1997 and 10.39% in 1996.

2.6.8 Centra's U-3 category includes capital expenditures for gas supply, peak shaving and storage. The 1997 budget of $538,000 was largely for initial expenditures to upgrade the control systems of the liquified natural gas ("LNG") plant at Hagar. The total cost of this project was estimated at $2 million.

2.6.9 Centra's U-5 category relates to capital expenditures for such items as office buildings, furniture and office equipment, computer equipment, tools and work equipment, transportation and heavy equipment.

2.6.10 Centra's capital budget in the U-5 category included $6.9 million in 1997 and $10.7 million in 1996 for IT expenditures. The details of these IT expenditures have been discussed earlier. Centra's 1996 budget also included $1.5 million for costs to replace the existing service centre in the City of Cornwall and $4.2 million to replace the Thunder Bay Service Centre.

2.6.11 Centra applied in E.B.R.O. 489 for approval of expenditures of $6.3 million for a new Thunder Bay Service Centre. While recognizing the inadequacies and inefficiencies of the existing facility, the Board disallowed the inclusion of the proposed capital expenditure in rate base because it was not satisfied that a new site was justified and that other alternative approaches, such as separation of functions at different sites to reduce costs, had been sufficiently explored.

2.6.12 Centra filed evidence in this case to justify the need for a new building and site. This justification was based on the City of Thunder Bay's plans to construct a bridge crossing the river at the current building site, which will greatly impede access and require expropriation of part of the site. Centra also filed evidence to support the development of a single site rather than separating functions at different sites and submitted a revised lower capital cost of $4.2 million for the construction of a somewhat smaller new building than previously proposed.

2.6.13 Centra's U-6 category represents capitalized administrative expenses and an allowance for CWIP. The U-7 category represents the capitalized costs associated with the retirement of facilities offset by the proceeds or salvage obtained from retirements. The U-8 category includes contributions in aid of construction. The U-9 category provides for expenditures on leases that generally accepted accounting principles require to be capitalized.

2.6.14 At the commencement of the hearing, the Board expressed concern about the rate impacts associated with the significant increases in the level of Centra's capital spending over the years 1995 to 1997 and requested a witness panel to explain the reasons for this increase and the processes Centra followed in developing and monitoring the capital budget. The witnesses' comments related to the capital budgeting process in general have been discussed in Section 2.2.

2.6.15 Centra's witnesses stated that its Executive recognised that the capital spending in 1996 was at a higher level than in previous years. Centra stated that in light of the increase, a greater level of detailed scrutiny was undertaken of each of the capital budget projects to ensure that the projects were needed and that economic criteria were met.

2.6.16 Centra stated that the primary areas of increase in the 1996 Capital Budget were attributable to: $10.3 million for new distribution business investment related to major industrial projects, including the addition of facilities to connect three cogeneration operations; increased investment of $7.7 million for system expansion to new communities not previously served, the largest of which were Tweed and Marmora/Deloro which together account for $5.1 million; and expenditures related to information technology, including the AM project, the ITE project and the BIS project.

2.6.17 Centra stated that the facilities to connect the cogeneration plants were single use facilities that all had a PI of greater than 1. Centra provided the information contained in Table 2.5 on the results of the discounted cash flow ("DCF") analysis of the four cogeneration projects for which facilities had been constructed in 1995 and 1996:

Table 2.5: Centra's Cogeneration Projects

	PI	**Revenue Deficiency/(Excess)**	**Impact on 1997 Deficiency**
Northland Power	1.19	first year $223,360 second year ($36,430) life average (160,000)	+ $93,500
Destec (Kingston)	1.51	first year ($484,000) second year ($196,000) life average ($365,000)	- $340,000
TCPL Kapuskasing	4.52	first year ($168,500) second year ($149,400)	- $159,000
TCPL North Bay	4.33	first year ($167,000) second year ($146,000)	- $156,000

2.6.18 In aggregate, these projects created a revenue excess of approximately $561,500 in 1997 and therefore Centra stated that the projects will not likely result in rate increases.

2.6.19 Centra's witnesses noted that the operations area was responsible for some 80% of the capital budget. The witnesses stated that because of the size of the overall capital budget, a careful review of the facilities investment projects had been made to confirm that the forecast of customer attachments was solid and that the estimates of required facilities and the costs to provide those facilities were sound. The profitability threshold of individual projects had to be met and the rolling PI was above 1.0. In this process the Company looked for opportunities to reduce costs or delay expenditures.

2.6.20 The witnesses explained that Centra had been in an expansion mode for a number of years and was responding to customer needs. Centra believed that while its investments created costs in the short-term, over the long-term ratepayers would benefit. However, Centra was facing a situation where customer gas usage was declining and the growth in the existing service areas was not providing sufficient revenues to offset short-term cost increases arising from system expansion.

2.6.21 Centra's witnesses stated that the Company was making significant investments in information technology to meet increasing needs for information, to position the Company for the future and to meet the Company's Shared Services commitment. Business cases had been prepared for each of the major IT projects. While recognizing that the IT expenditures were large, Centra expected to achieve long-term savings from these projects that would result in both cost reductions and future avoided costs. Further, the witnesses stated that it was necessary for Centra to make the technology investments now to take advantage of the savings resulting from Shared Services and to avoid maintaining parallel systems at Centra and Union.

2.6.22 Centra's witnesses explained that the 1996 capital budget process was commenced in early 1995 and the budget was presented to the Executive in June 1995. At that time no significant rate impact in 1996 and beyond was expected and, in fact, a small sufficiency in 1996 was expected. As a result Centra did not apply for a rate change for 1996.

2.6.23 Centra stated that when it filed its 1997 Rate Application in March 1996, a small revenue deficiency in 1997 of $16 million was projected. When it had prepared its evidence in May 1996, the deficiency had increased to $29 million, largely because of increases in gas costs. Since then the projected deficiency had increased to the current forecast level of $45 million. However, the 1996 Capital Budget had been set and no changes were made to that budget as it related to the projected 1997 deficiency.

Centra stated that it was difficult to cut back on distribution new business projects once the capital budget had been set and dollars committed, since expectations for service had been created in communities they planned to serve.

2.6.24 The Company's evidence indicated that 58% of the projected revenue deficiency for 1997 was attributable to higher gas costs and 42% to an increase in the delivery component. The delivery component was largely driven by the increase in the Rate Base. Centra's evidence indicated that between 1995 and 1997 there had been a delivery margin increase of $6.0 million while its rate base had grown by $115.4 million resulting in annualized costs of more than twice the margin. Since 1991 Centra indicated that its rate base had increased by 60% but its customer base had increased by only 40%.

2.6.25 Centra's witness stated that in reviewing the deficiency, its focus was on all elements contributing to the deficiency and not just on the capital budget. The witnesses stated that a major factor that contributed to the 1997 deficiency was the settlement with Revenue Canada which required the capitalization, for tax calculation purposes, of administrative and overhead expenses that had previously been deductible on a current basis. When grossed up on a pretax basis this contributed $12 to $15 million to the overall deficiency.

2.6.26 Centra's witnesses stated that as a result of the ADR Settlement Agreement the Company had revised its capital spending forecasts for 1996 from $106.3 million to $101.8 million and for 1997 from $81.4 million to $84.8 million, including the impact of the Thunder Bay Service Centre Project shifting from 1996 to 1997.

ADR Settlement Agreement

2.6.27 The following parties participated in the discussion of some or all of Centra's capital budget issues: Kitchener, Schools, NOVA, Board Staff, CAC, ECNG, Energy Probe, NRG, IGUA, OCAP and NOVA.

2.6.28 The ADR Settlement Agreement stated that:

The parties agreed that Centra's 1996 and 1997 Capital Budgets should be accepted on the following basis. If possible, Centra will reflect the outcome of the E.B.A. 728/E.B.C.241 franchise and facilities proceeding concerning the Township of Harris in the evidence pertaining to 1997 in this case. Specifically if the project was not approved or if the capital budget were to change, the parties agreed that the evidence should be updated to reflect any changes. The agreement to accept Centra's evidence in connection with the 1996 and 1997 budgets was subject to receiving satisfactory explanations concerning Centra's 1995 new business spending; expenditures on the Northland Power compressor project, and increased costs in Centra's U-2 capital budget for 1995. These explanations were provided (and the Board assumes accepted by the parties) *and summarized in Schedule B attached to this ADR Agreement. Centra also agreed to continue to provide detail on capital budget items in excess of $200,000 rather than to change the limit to $500,000 as for Union.*

2.6.29 In Schedule B to the ADR Settlement Agreement Centra showed that the variance in its 1995 distribution new business spending resulted from increased installation of mains to meet current and future customer needs, more expensive costs to attach scattered customers and a greater need to use contractor crews, which were more expensive than Company crews. Centra also provided a breakdown of the variances between the actual and budgeted 1995 expenditures for system betterment projects.

2.6.30 In Schedule B, Centra also explained that a compressor was required to meet the contracted delivery pressure for the Northland Power cogeneration project which is 100 psig higher than the guaranteed TCPL delivery pressure at the TCPL takeoff point at Iroquois Falls. Centra considered three alternatives to meet this requirement each of which was rejected. Centra was unable to negotiate a deal with Northland Power to accept TCPL's guaranteed lower pressure, because the customer's equipment could not be modified to accept a reduced delivery pressure. Northland Power could not finance the compressor station if it had to build on its own. TCPL could not guarantee a suitable delivery pressure without building a compressor. Centra considered that it could not protect itself from unacceptable financial risks were it to accept the risk that the delivery pressure from TCPL would not meet the required contracted delivery pressure for Northland Power. Centra's feasibility analysis of the overall project included the $3.6 million for the compressor station and indicated a PI of 1.19.

2.6.31 Centra gave evidence in the hearing that the project costs of the Northland Power project were on target, and that at the time of full load test of the power plant, the compressor was needed because TCPL was operating at reduced pressure. Further, TCPL had, on three occasions during the winter of 1995/1996, delivered less than the contracted Northland Power delivery pressure at the Iroquois Falls take off point.

2.6.32 The parties to the ADR Settlement Agreement also agreed to recommend approval of Centra's proposal for the construction of a new Thunder Bay Service Centre, subject to Centra revising the in-service date for the facility to November 1, 1997 and making the related adjustments to Rate Base. The parties accepted Centra's evidence on the need for the facility and the Company's response to the concerns expressed in the E.B.R.O. 489 Decision.

Positions of the Parties

2.6.33 The Companies argued that there was no evidence on the record that would justify any adjustments to Centra's capital budgets and requested an opportunity to address any changes the Board may propose.

2.6.34 In argument IGUA commented that "while IGUA shares the Board's concern with the impact that Centra's 1996 capital spending has on rates for 1997, there is no evidence of which IGUA is aware, to indicate that Centra's capital spending did not meet the feasibility criteria which the Board considers to be appropriate." IGUA also noted that "since 1996 was not a test year for Centra, there was no Board approved capital budget ceiling to constrain Centra's capital spending. It was in the context of the fact that the capital spending related to projects which apparently satisfied Board approved feasibility criteria, that IGUA agreed that Centra's 1996 Capital Budget should be accepted."

Board Findings

2.6.35 Of the number of factors contributing to Centra's large 1997 deficiency, the Board has identified three major causes: an increase in the cost of gas; a change in the allowed tax treatment of costs associated with overhead and administration expenses; and, a significant increase in the capital budget over that last approved by the Board in 1995.

2.6.36 The Board is concerned that Centra did not take steps to adjust its capital budget in an effort to partially offset other largely unavoidable increases. The Board recognizes the nature of capital projects necessitates longer term planning and consistency and that this introduces a certain amount of rigidity in the capital budgeting process. The Board also understands Centra's reluctance, having raised community expectations, to change the capital budget for distribution new business. However, the Board notes the large increase in the U-5 general category for 1996 and 1997 which is predominantly made up of items over which the Company has a greater degree of discretion.

2.6.37 The Board is of the view that Centra, having been made aware of the effect of the change in tax ruling in early 1996, should have undertaken a significant review of its capital spending plans for 1996 and 1997.

2.6.38 The Board has earlier expressed its concerns with the level of capital spending and made specific findings in the area of information technology. In addition to these specific findings, the Board has considered the rate impact that resulted from the absence of a timely capital budget review in making the adjustments to Centra's capital budget and rate base.

2.6.39 The Board notes that at the same time that the Company is investing significantly in IT projects, it is also proceeding with major projects to construct new service centres in Cornwall and Thunder Bay. The Board questions whether there was not more flexibility to adjust the schedule of these projects and to scale down their scope. The Board notes in this regard Centra's initiatives in scaling down the scope of the Thunder Bay Service Center Project. The Board accepts Centra's rationale on the need for and scope of the Thunder Bay Service Centre Project, and concurs with the adjustment to rate base agreed to in the ADR Settlement Agreement. Moving the in-service date for Centra’s Thunder Bay Service Centre from 1996 to November 1997 results in a reduction of $3,938,000 to gross plant. As the opening asset balance is affected by this adjustment, a reduction of $106,000 to depreciation expense and $53,000 to accumulated depreciation is required. The adjustment to capital cost allowance is discussed below.

2.6.40 With regard to capital expenditures on distribution new business development, the Board observes that one of the projects included in Centra's Capital Budget for 1996 in the U-4 category is a project to connect the community of Finch. The Board notes that the in-service date for this project is shown as November 1996. Centra did not file the franchise and certificate Application E.B.A. 755/E.B.C. 254 until November 1996, which showed a construction schedule that would continue through September 1997. The Board further notes that no application has as yet been filed with the Board in relation to the South Mountain project. Further the Board notes in Exhibit B6 Tab 3 Schedule 2 Page 2 the transfer into rate base in December 1997 from Construction Work in Progress of $1.48 million related to storage project land rights. The Board has inferred that this transfer relates to the Consumers' Gas Coveney and Black Creek Storage Development Project which is the subject of an Application currently before the Board [E.B.L.O. 258 et al]. While not disallowing these three projects from Centra's capital expenditures, given the uncertain timelines and the limited evidence on these projects in this hearing, the Board has not included these projects in the Rate Base for ratemaking purposes in fiscal 1997.

2.6.41 As a result of the removal of the Finch project in fiscal 1996 and 1997, the Board has removed the full $1.588 million cost of the project from Centra’s 1997 gross plant forecast. The Board has determined that the Company’s capital cost allowance should be reduced by $64,000. As the capital expenditure was not incurred in 1996 as originally forecast, this adjustment impacts the opening asset balance in 1997 upon which depreciation is calculated. The Board has determined that depreciation expense should be reduced by $42,000, and accumulated depreciation by $21,000 based on an average of monthly averages. In addition, since the Company will not earn the margin associated with the 110 first year customer additions forecast for this project, the Board has determined that revenues should be reduced by $27,000.

2.6.42 Removal of $1.549 million attributable to the South Mountain distribution project, forecast to be in-service November, 1997, will result in a $258,000 reduction to Centra’s Rate Base. The Board has determined that a reduction of $31,000 to capital cost allowance is appropriate.

2.6.43 Deferral of the transfer of $1.480 million from CWIP associated with the Coveney and Black Creek Storage Project, forecast to be transferred in December, 1997, will result in a $123,000 reduction in rate base. The Board has determined that the reduction to capital cost allowance shall be $30,000.

2.6.44 As a result of the capital budget adjustments in the areas of the IT capital budget, the BIS, and the deferral of the In-Service date for the Thunder Bay Service Centre Project, the Board approves a reduction to capital cost allowance of $269,000 as provided for in the ADR Agreement financial summary. After providing for the adjustments agreed to in the ADR Settlement Agreement and the above adjustments, the Board accepts Centra's capital expenditures as reasonable for ratemaking purposes, and finds that Centra's Rate Base for the test year should be adjusted accordingly.

2.7 OVERALL BOARD FINDINGS ON 1997 CENTRA AND UNION RATE BASES

2.7.1 Centra forecast an allowance for working capital of $30.071 million. Centra increased the accounts receivable component of this allowance by $24.169 million to reflect the outcome of the ADR Settlement Agreement regarding the inclusion of the MFP in utility operations. Centra made a reduction of $10,000 in its forecast cash requirements of $1.776 million to reflect other adjustments resulting from the Agreement in the areas of gas costs and O&M expenses. Despite the fact that the E.B.R.O. 493-01 and -02 Interim Rate Orders issued December 24, 1996 and February 17, 1997 resulted in a gas cost increase of $23.846 million, Centra did not request an adjustment to its cash requirements. As the Board's reductions to O&M expense of $0.675 million is immaterial by comparison, the Board finds that no further adjustment is required. Accordingly the Board approves a cash working capital component of $1.766 million. The Board has determined that the resulting allowance for all Centra's components of working capital shall be $54.230 million.

2.7.2 The financial impacts relating to Board findings have been included with its specific findings, rather than in this summary. For Centra, Appendix F serves as a summary of the forecast Utility Plant and Allowance for Working Capital components used to derive Centra's proposed 1997 Rate Base of $772.540 million. Appendix F also shows the specific impact of adjustments to these components resulting from the ADR Settlement Agreement and adjustments made by the Board in this Decision. The resulting Board-approved Utility 1997 Rate Base for Centra is $786.047 million.

2.7.3 Union forecast an allowance for working capital of $160.208 million. Union increased the accounts receivable component of this allowance by $81.367 million to reflect the outcome of the ADR Settlement Agreement regarding the inclusion of the MFP in utility operations. Union made a reduction of $35,000 in its forecast cash requirements of $9.536 million to reflect other adjustments resulting from the ADR Agreement in the areas of gas costs and O&M expenses. Despite the fact that the E.B.R.O. 493-01 and E.B.R.O. 493-02 Interim Rate Orders issued December 24, 1996 and February 17, 1997 resulted in an increase in gas costs of $44.860 million, Union did not request an adjustment to its cash requirements. As the Board's reductions to O&M expense of $2.347 million is immaterial by comparison, the Board finds that no further adjustment is required. Accordingly the Board approves a cash working capital component of $9.501 million. The Board has determined that the resulting allowance for all Union's components of working capital shall be $241.540 million.

2.7.4 For Union, Appendix B serves the same purpose as Appendix F for Centra but it also includes Deferred Taxes. Appendix F shows that the ADR Settlement Agreement has resulted in a $79.344 million increase to Utility Rate Base from the $2,134.852 million proposed by the Company. The resulting Board-approved Utility 1997 Rate Base for Union is $2,214.196 million.

3. UTILITY INCOME

3.0.1 The Companies' forecast of Utility Income before income taxes for the test year is derived from the forecast *Operating Revenue* including, Gas `Sales', S&T revenue together with Other Revenue; net of the forecast *Cost of Service Expenses*, including: Gas costs, O&M expenses, Depreciation expense, Financing costs, and Property and Capital taxes.

3.0.2 The Board has separated the evidence, positions of the parties and Findings on the following Cost of Service matters into subsequent Chapters of this Decision in order to deal more fully with these:

- Demand Side Management (O&M) - Chapter 4;
- Affiliate Transactions - Westcoast Corporate Centre Charges - (O&M) Chapter 5; and
- Cost of Gas - Chapter 6.

3.0.3 The financial impact of the Board's Findings in these Chapters are included in the Overall Findings on Utility Income set out in Section 3.14 of this Chapter.

3.0.4 The figures quoted in this Chapter, except where otherwise noted as resulting from the ADR Settlement Agreement or a Board Finding, are from the Companies' prefiled evidence update of August 30, 1996. The effects of the Board's E.B.R.O. 493/494-01/02 Interim Rate Orders, related to forecast gas costs for 1997, are not included in the Operating Revenue figures until Section 3.14.

3.0.5 In this proceeding Union proposed to change its accounting treatment of income taxes from a normalized or deferred basis to a flow through basis. However, it proposed to continue to treat income from its rental programs on a flow through basis. The change from deferred accounting for income taxes is dealt with in Chapter 7. The treatment of income from rental programs is dealt with in this Chapter.

3.0.6 The forecast 1997 Utility Income for each Company as set out in its updated prefiled evidence of August 1996, before ADR Settlement Agreement and Board adjustments, is summarized in Table 3.1.

Table 3.1: 1997 Utility Income ($000's)

Union		**Centra**	
Operating Revenue		**Operating Revenue**	
Gas Sales	887,677	Gas Sales	452,752
Contract Carriage	49,546	Contract Carriage	0
Transportation and Storage	157,391	Transportation and Storage	22,088
Other Revenue	91,933	Other Revenue	35,526
Total Revenue	**1,186,547**	**Total Revenue**	**510,366**
Cost of Service Expenses		**Cost of Service Expenses**	
Gas Costs (1)	545,383	Gas Costs (1)	318,293
Operations and Maintenance	221,195	Operations and Maintenance	73,406
Depreciation and Amortization	118,253	Depreciation and Amortization	37,885
Shared Services Amortization	1,892	Shared Services Amortization	1,394
Financing Charges	0	Financing Charges	352
Property and Other Taxes	37,337	Property and Other Taxes	11,149
Total Cost of Service Expenses	**924,060**	**Total Cost of Service Expenses**	**442,479**
Utility Income before Income Taxes	**262,487**	**Utility Income before Income Taxes**	**67,887**

(1) As per August 30 update excluding effect of E.B.R.O. 493/494-01/02 Interim Rate Orders

OPERATING REVENUE

3.0.7 The Companies presented separate prefiled evidence on the Operating Revenue forecasts for Union and Centra for the 1997 test year. However some of the issues were addressed together in the ADR process and by the Companies' witness panels.

3.0.8 The ADR settlement process resulted in the parties reaching agreement on a number of issues including Economic Forecast, Gas `Sales' revenues and S&T revenues.

3.1 ECONOMIC FORECAST

3.1.1 The economic outlook provides the background for the operating revenue forecast. The Utilities' and Board Staff's experts provided forecasts for key economic variables.

3.1.2 The Companies' and Board Staff's experts forecast GDP growth at between 3.6% - 3.7% respectively in 1997. Board Staff's expert estimated an unemployment rate of 9.3% while the Utilities estimated the rate to be 8.5% for the test year. The Utilities' experts forecast an annual increase in the consumer price index of 2.4%, while Board Staff's expert's estimate was 1.4%. According to the Companies' and Board Staff's experts, the forecast housing starts in Ontario for 1997 were 55,000 and 47,500 respectively.

3.1.3 The parties to the ADR Settlement Agreement while not accepting the Companies' Economic Forecast agreed that there were no issues other than the specific matters dealt with under the revenue forecast for 1997.

3.2 FORECAST REVENUES FROM GAS `SALES'

3.2.1 The Companies' customers are divided into two groups: contract customers who are served under the terms of a written contract; and, general service customers who are served under the general service provisions without a written contract. Revenues from gas 'sales' to general service customers are estimated by forecasting the average number of customers in the test year and their average gas consumption, adjusted, or normalized, for variations in weather. Contract customer consumption and revenue forecasts are based on the contracted volumes and a survey of customer expectations for the test year.

Centra

3.2.2 Centra forecast that in 1997 it will serve an average 253,892 general service customers (Rates 01, 10, 16) receiving either gas `sales' or bundled transportation ("bundled-T") service and 190 contract customers. Based on the rates in effect at the time of filing, these customers would generate $452.752 million in Gas `Sales' Revenues.

3.2.3 The parties to the ADR Settlement Agreement agreed with Centra's customer additions, volume throughput and Gas `Sales' Revenue forecast for 1997.

Union

3.2.4 Union forecast for 1997 an average of 773,951 general service customers (Rates M2, M4, M5, M6, M7, M9 and M10) and 448 contract customers. Based on the then current rates, gas ‘sales’ from these customers would generate $887.678 million and $49.546 million respectively in revenues.

3.2.5 As part of the ADR Settlement Agreement the parties agreed to increase the contract customer volume forecast by 2% or 66,000 10^3m^3. This increase in volumes resulted in an increase in forecast 1997 Gas `Sales' Revenue of $1.178 million based on rates then in effect.

3.2.6 The parties to the ADR Settlement Agreement further agreed to increase the forecast annual volume for Union’s M9 customers by 7,744 10^3m^3 to reflect past consumption patterns and the impact of a plant expansion in NRG’s service territory. The corresponding increase in forecast Gas `Sales' Revenue was $0.905 million.

3.3 FORECAST REVENUES FROM STORAGE AND TRANSPORTATION SERVICES

Centra

3.3.1 Centra's S&T services were forecast to generate $22.088 million in revenues in 1997 based on rates in effect at the time of filing. The parties to the ADR Settlement Agreement agreed with this forecast.

Union

3.3.2 Union's S&T services, including M12 and C1 services, based on rates in effect at the time of filing, were estimated to generate $157.391 million in revenues in the 1997 test year. In addition, contract revenues were forecast at $49.546 million for a total of $206.937 million. Parties to the ADR Settlement Agreement supported an increase to S&T revenues of $100,000 in M12 Overrun revenues, a $300,000 increase in Exchange revenues, and a $200,000 increase in other S&T revenues namely off-peak storage, gas loans, redirections, name changes, and balancing. The ADR Settlement Agreement noted that these adjustments reflected the historic experience of revenues earned by Union from these services.

Board Findings

3.3.3 The Board finds that the Companies' prefiled evidence and the ADR Settlement Agreement provides a sufficient evidentiary base and indication of the positions of the parties on the following issues related to the gas 'sales' forecast for the test year:

- Economic Forecast;
- Union and Centra forecast Gas 'Sales' Revenues; and
- Union and Centra forecast S&T Revenues.

3.3.4 The Board accepts the Companies' economic forecasts as per the ADR Settlement Agreement.

Centra

3.3.5 As a result of the Board’s E.B.R.O. 493-01 Interim Rate Order of December 24, 1996, Centra’s forecast Gas `Sales' Revenues increased by $24.330 million. This increase reflects the Board’s approval of Centra’s evidence regarding its forecast gas cost increase of approximately $21.211 million in fiscal 1997, less $0.670 million reflected in the Company's August 30, 1996 evidence update for adjustments for commodity costs related to delivered service and incremental U.S. supplies and interruptible transportation charges. The Gas `Sales' Revenue was increased by a further $3.789 million to reflect an increase in the firm WACOG from $1.45 to $1.48/GJ as a result of approval of Centra’s Quarterly Rate Adjustment Mechanism Application in December, 1996.

3.3.6 Centra’s Gas `Sales' Revenue was increased by a further $20.727 million as a result of the Board’s E.B.R.O. 493-02 Interim Rate Order of February 17, 1997 to reflect an additional increase of $20.727 million in gas costs from those reflected in the E.B.R.O. 493-01 Interim Rate Order.

3.3.7 Subject to these gas cost-related revenue adjustments, the Board finds Centra's proposed Gas `Sales' Revenue forecast for 1997 acceptable for ratemaking purposes. The Board further accepts Centra's forecast regarding S&T Revenues.

Union

3.3.8 Interim gas cost increases also affected Union’s 1997 forecast costs and revenues. As a result of the E.B.R.O. 494-01 Interim Rate Order of December 24, 1996, Union’s forecast Gas `Sales' Revenues increased by $27.283 million. This increase reflects the Board’s approval of Union's evidence regarding its forecast gas cost increase of approximately $34.207 million in fiscal 1997, less Union's revision of $6.924 million filed with the Board in November, 1996.

3.3.9 Union’s forecast revenues were increased by a further $51.784 million as a result of the Board’s E.B.R.O. 493-02 Interim Rate Order of February 17, 1997 to reflect an additional increase of $51.784 million in gas costs from those reflected in the E.B.R.O. 494-01 Interim Rate Order.

3.3.10 The Board accepts Union's 1997 Gas `Sales' Revenue forecast, as adjusted to reflect the gas cost-related revenue adjustments discussed above, including the modified Union M9 and contract throughputs, for the purpose of determining the test year rates. The gas costs associated with the volume adjustment for M9 volumes have been increased by $981,000 based on the use of 61.5% delivered supply and 38.5% delivered spot supply costs as provided in the financial statements supporting the ADR Settlement Agreement. The gas costs associated with the 2% increase in certain contract volumes has been increased by $418,000.

3.3.11 The Board finds that the Union's S&T Revenue forecast, increased by $600,000 resulting from the impact of reflecting the historic receipt of revenue earned from exchanges, M12 overruns and other S&T activities is reasonable for the purpose of establishing rates for the 1997 fiscal year.

3.3.12 The Board has made additional Findings on the following issues arising from the Companies' evidence and the ADR Settlement Agreement:

- Gas `Sales'-General Service Additions and Normalized Volume Forecast;
- Ancillary Programs - Rental and Financing Programs;
- On Bill Third Party Financing; and
- Allocation of Water Heater Rental Revenue.

3.4 GAS `SALES'- GENERAL SERVICE ADDITIONS AND NORMALIZED VOLUME FORECAST

3.4.1 Although this issue was addressed in the ADR Settlement Agreement and the 1997 M9 volume forecast adjustment, the Board questioned Union and Centra further regarding the methodology which resulted in Union's Rate M2 and Centra's Rates 01 and 10 normalized average consumption ("NAC") per customer (residential, commercial, industrial) being adjusted from the initial filing to the update as follows:

	Original	Update
Union		
! M2 residential NAC	2.910 10^3m^3	2.932 10^3m^3
! M2 small Commercial NAC	16.850 10^3m^3	17.571 10^3m^3
! M2 small Industrial NAC	59.204 10^3m^3	65.071 10^3m^3
Centra		
! Rate 01 Residential NAC	3.730 10^3m^3	3.615 10^3m^3
! Rate 10 Commercial NAC	134.520 10^3m^3	128.674 10^3m^3

3.4.2 The Companies responded that for both Union and Centra, the methodology used to forecast NAC is a detailed analysis that is prepared at the regional level within each Company's franchise territory and reflects the impact of the use of more energy efficient new and replacement equipment. There are 14 regions in total and for each region the historical NAC is examined on an annual and monthly basis using various statistical techniques including time series and regression analysis. In addition, appliance end use and commercial market trends are incorporated.

3.4.3 The Companies stated that the historic decline of the Union Rate M2 residential/commercial and Centra Rate 01 NAC over the past several years, exhibit relatively stable trends, reflecting in part the relatively homogeneous customer base. The forecast NACs for 1997 follow the historical trends for both Companies.

3.4.4 The methodology used to forecast the Union Rate M2 industrial and Centra Rate 10 NACs is also based on monthly forecasts at the regional level. In this case major economic changes have affected the historic data and so the forecast relies on current year over previous year analysis, as opposed to analysis of long-term trends. New technology impacts were key considerations in preparing the 1997 NACs for these customers. New technology tends to reduce NACs while economic trends can impact either way, depending on whether these are positive or negative for the businesses comprising this group of customers.

Board Findings

3.4.5 The Board finds that the Companies' methodology for the *small volume residential/commercial customer NACs* should include the effect of recent trends, such as the impact of rate increases, gas price changes, technology or customer behaviour.

3.4.6 It was the Companies' prefiled evidence that in the case of the Centra Rate 01 and Rate 10 customers, they were observing some recent upward changes in consumption that related to customer behaviour. However, the updated Rate 01 and Rate 10 NAC forecasts reflected continued declining use per customer due to extrapolation of the historic long-term average data. The Board observes that, intuitively, the slope of the curve representing the conservation/efficiency impact on the NAC must at some point flatten out, even taking into account the Companies' DSM programs. The Companies may well miss this effect unless they develop forecast techniques to include multiple regression analysis and weighted time series analysis. In the case of Centra's Rate 01, the actual NACs are higher than the forecast NACs from 1992 which might lead to the conclusion that the long-term declining trend is not holding.

3.4.7 In the case of Union's M2 residential and small commercial customers, the Companies increased the forecast use in their updated evidence. However the data show that since 1992, actual NACs have been higher than forecast NACs and this has in the past resulted in higher operating revenue than forecast.

3.4.8 For the industrial and larger commercial customers, Union Rates M4, 5, 6, 7, 9, and 10 and Centra Rates 20, 25, 100, where the NACs are impacted in a major way by economic trends, the Board agrees that a bottom up year over year analysis will continue to produce the best forecast and that no change in methodology is warranted.

3.4.9 The Board accepts the Companies' forecasts of NACs for the 1997 test year.

3.5 ANCILLARY PROGRAMS

3.5.1 The Companies 1997 ancillary services include the following as part of the utility business:

- MFP;
- equipment rental;
- merchandise sales;
- NGV;
- other services and charges.

3.5.2 Union’s ancillary programs including its rental program and MFP. These are forecast to contribute $91.933 million in revenues in the 1997 test year.

3.5.3 Union's initial proposal was to maintain the rental program on a deferred tax accounting basis. As part of the ADR Settlement Agreement Union agreed instead to use a flow-through tax accounting basis for the test year, consistent with its proposal for its other regulated operations.

3.5.4 In E.B.R.O. 486 the Board directed Union to file evidence explaining why its MFP should not be removed from the regulated utility operations. In response Union filed in this proceeding a proposal for removal of the MFP on a basis consistent with that ordered by the Board for Consumers' Gas in E.B.R.O. 452. The effect of removing the MFP from the Cost of Service was a decrease in forecast 1997 Operating Revenue of $11.177 million and a reduction in the revenue requirement of the Utility by $878,000.

3.5.5 Revenue from Centra's rental program, MFP, late payment fees, heating insurance plan, account opening charges and other ancillary services were forecast to generate $35.526 million in revenue in the 1997 test year.

3.5.6 Centra also initially proposed removal of its MFP from the regulated entity. The effect of this proposal was to reduce forecast 1997 revenue by $3.005 million and increase the revenue requirement by $285,000.

3.5.7 HVAC retained Alliance Strategies Incorporated ("ASI") to examine the appropriateness of the method of removal of the Companies' MFPs from the regulated utility. ASI's expert concluded that leaving the MFPs in the regulated Utilities was inappropriate and resulted in cross-subsidization as does the use of marginal cost allocation between the utility and non-regulated affiliate.

3.5.8 ASI's expert recommended that the Board should direct the Utilities to:

- conduct an independent valuation study to determine the fair market value of the MFP businesses of the Companies;
- determine the proper level of equity investment in the MFP non-regulated affiliate and restate the utility capital structure accordingly;
- apply a cost driver approach to shared costs related to MFP businesses;
- establish balancing accounts to protect the interests of shareholders and ratepayers until the valuation study is completed and issues resolved;
- develop a separation plan including a code of conduct; and
- hold a collaborative workshop to resolve outstanding issues.

ADR Settlement Agreement

3.5.9 As part of the ADR Settlement Agreement, Union and Centra agreed to maintain their MFPs in the Cost of Service for 1997. This increased forecast 1997 revenues by $11.177 million for Union and $3.005 million for Centra. Some parties had concerns with this proposal as well as with the approach to removal of the merchandise sales and rental programs. In response, the Companies undertook to provide, in the next rates case, studies which would address the following matters:

- removal of the MFP, sales and rental programs on a fully allocated and marginal cost basis;
- codes of conduct for affiliate transactions;
- corporate structures;
- market value analysis; and

! reporting mechanisms for affiliate transactions related to these functions.

A deferral account to record the cost of these studies was recommended by the parties to the ADR Settlement Agreement.

3.5.10 The Companies also undertook to provide a forum in which to discuss the issue of removal of ancillary services from the Cost of Service.

3.5.11 There was some disagreement as to whether the Companies should complete a study for all ancillary services, regardless of whether the Companies propose to remove these from the regulated business, and in particular, what was practical to do for the 1998 test year filing.

3.5.12 The Companies' witnesses, while acknowledging that the Companies will eventually have to examine the costs associated with all ancillary services, stated that it was not practical to complete studies of more than one or two ancillary programs for the 1998 test year, especially since the details of the study methodology were still to be worked out and external assistance may be required.

Positions of the Parties

3.5.13 The Companies submitted that they will do all they can to design and implement the work described in the ADR Settlement Agreement with respect to any programs the Companies propose to remove from their 1998 Costs of Service. However in their view, it is not realistic to give commitments to do similar studies on programs that will not be removed from the Utilities' regulated businesses.

3.5.14 IGUA and OCAP both submitted that to ensure there is no cross-subsidy between monopoly and non-monopoly programs, the cost studies should be done even for those programs that will remain in the Utilities in 1998.

3.5.15 HVAC supported IGUA's and OCAP's position, taking the view that the studies may show that other programs should be removed from Cost of Service.

3.5.16 CAC, OCAP and HVAC all submitted that the Companies should be directed to file studies for all ancillary programs in the next rates cases, or justify at that time why they have not done so.

3.5.17 Union and Centra in reply reiterated that neither the approach, nor methodology respecting the cost allocation studies has been developed and other important matters must be addressed by their staff for the next rates case. The Companies submitted that the Board can be assured they will make every effort to bring forward as much detail as possible in the 1998 rates cases and they intend to proceed expeditiously with plans in line with their new strategic direction. Accordingly, the Companies submitted that no Board directive need be made at this time.

Board Findings

3.5.18 The Board understands that fully allocated costing of ancillary programs has not been deemed necessary in the past and that marginal costing has been the basis of the Board's previous decisions on ancillary programs within regulated utilities. However the Board finds the evidence of HVAC's expert, filed in this proceeding, to be persuasive and considers a fully allocated cost methodology to be appropriate for equitable separation and removal of ancillary programs from the regulated Utilities. The methodology may also be appropriate for analyzing the impact on rates of ancillary programs within the Utilities and activities involving the use of Utility resources by non-regulated affiliates.

3.5.19 The Board therefore supports the studies agreed to in the ADR Settlement Agreement and directs the Companies to proceed expeditiously with outside assistance to finalize the methodology and to apply it to as many programs as possible, but as a minimum to any programs proposed to be removed in the 1998 test year, and in addition to any activities by affiliates which use regulated Utility resources.

3.5.20 With regard to programs remaining in the Utilities for 1998, the Board draws to the Companies' attention previous Board approvals based on treating ancillary programs as a package, with the requirement that the forecast rate of return of the package equals or exceeds the forecast test year allowed utility rate of return. Accordingly the Board directs the Companies, at a minimum, to group together residual ancillary programs not being removed from Cost of Service in 1998 and to cost these on both a marginal and fully allocated cost basis so that intervenors can determine the rate of return on either basis and, if necessary, the Board can deem the appropriate Utility return for estimating the 1998 test year Cost of Service and revenue requirement.

3.5.21 The Board accepts the outcome of the ADR Settlement Agreement on Union's rental programs for fiscal 1997, subject to the findings made in the section "Allocation of Water Heater Rental Revenue".

3.5.22 The Board also accepts the ADR Settlement Agreement that the MFPs should be maintained in the Companies' Utility operations for ratemaking purposes for the 1997 fiscal year.

3.5.23 As a result of the inclusion of the MFPs in the Utilities' operations: Union's working capital will increase by $81.367 million, Other Revenues will increase by $11.177 million, O&M Expense will increase by $857,000, and Capital Taxes will increase by $230,000 and Large Corporation Tax will increase by $197,000. Inclusion of the MFP will increase Centra's allowance for working capital by $24.169 million, Other Revenues will increase by $3.005 million, and O&M Expense will increase by $358,000. Centra did not make any specific adjustments to its Capital Taxes or Large Corporation Taxes in the financial schedules supporting the ADR Settlement Agreement, and the Board has determined that no further adjustments of significant consequence are required.

3.6 ON BILL THIRD PARTY FINANCING

3.6.1 The parties to the ADR Settlement Agreement did not reach agreement on the related issue of third party financing as a complement to, or replacement for, the Companies' own MFPs.

3.6.2 In this regard, the Companies' evidence was that there is a lack of interest by third party financial institutions in linking up with the Companies. They noted, for example, that the single respondee to a Consumers' Gas' request for proposal had proposed a higher interest rate than that charged by Consumers' Gas. In addition, the Companies' witnesses expressed concerns about technical obstacles within the CIS which prevented their moving from single one time billings to regular monthly billing for third party merchandise or services.

Positions of the Parties

3.6.3 Pollution Probe submitted that Centra had not lived up to its commitment in E.B.R.O. 483/484 and E.B.R.O. 489 to make best efforts to investigate and implement on bill third party financing.

3.6.4 Pollution Probe asserted that a cooperative arrangement between the Companies and a third party financial institution would allow the Companies to eliminate their MFPs, lower customers' costs of financing gas equipment and appliances, promote fuel switching and energy efficiency and meet Centra’s E.B.R.O. 483/484 commitment.

3.6.5 Pollution Probe argued that the Board should set Centra’s 1997 return on common equity at less than the 11.75% agreed to in the ADR Settlement Agreement, because of Centra's failure to comply with its commitments and should also direct Centra to make best efforts to comply with its commitment in 1997.

3.6.6 GEC submitted that the Companies offered a string of (unconvincing) excuses for their failure to honour the E.B.R.O. 483/484 ADR Agreement. In GEC's view, the only real issue is the cost of altering the software, a task that will be done in the summer of 1997 for ABC Service, should the Board approve this service.

3.6.7 GEC submitted that flexible on bill third party financing will be even more appropriate in the post separation environment when all third parties should have similar access to the Utilities’ distribution customers. GEC argued that Centra should be directed to have an on bill third party financing system in place at the time that separation occurs and that given the long delay, Union should be directed to implement the system forthwith.

3.6.8 In reply the Companies reiterated that the primary obstacle to on bill third party financing was the lack of interest of third parties and it would, in the Companies' view, be putting "the cart before the horse" to spend further time and resources investigating technical barriers in light of this lack of interest.

3.6.9 The Companies submitted that they had made best efforts to look into third party on bill financing and no direction from the Board was warranted at this time.

Board Findings

3.6.10 The Board finds that there are three related issues being raised by intervenors and the Companies:

- third party financing as an alternative to the Companies' MFPs;
- third party billing on the Companies' gas bills; and
- access to third party billing.

3.6.11 Based on the evidence in this proceeding it is unclear to the Board why the Companies have not made more progress in implementing a third party financing program as an alternative or complement to the Companies' MFPs. There may be legitimate reasons, such as lack of third party interest as the Companies noted was the case for Consumers' Gas, or there may be competitive aspects which the Companies hope to reserve for their affiliates, such as Union Energy Inc. ("Union Energy"). Given the plans to separate the MFPs in 1998, the Board will await the results of the studies and the Companies' proposals in this regard.

3.6.12 The Board is unconvinced there are any major technical issues to third party billing on the Companies' gas bills ("on bill third party billing"). The Companies will offer this at a fee for ABMs under ABC Service, given the Board's approval of this service later in this Decision. Union is already is providing a limited service for its Union Energy affiliate. The remaining technical issues cited by the Companies, such as single payment versus regular automatic payments adjusted for prior payments, in the Board’s view, are all solvable with an appropriate application of skilled resources. The Board notes that other utilities already offer customers the ability to “put it on your gas bill”. The Board directs the Companies to file complete evidence on their ability to provide on bill invoicing for third parties and the costs to upgrade the CIS to provide this capability, in the next rates case.

3.6.13 The Board also expects Union and Centra to adhere to the principle that after separation of their own merchandising and finance programs, any system of on bill third party invoicing or billing will be available on an equal access basis to affiliates and other legitimate third parties, such as heating equipment supply and servicing companies, who are providing products or services to the Utilities' customers. The criteria for access to the on bill invoicing/billing service should include clear benefits to customers from the product or service being offered and payment of the fully allocated costs of the billing service by the third party.

3.7 ALLOCATION OF WATER HEATER RENTAL REVENUE

3.7.1 Under the category of Other Revenue, Union's rental program was forecast to generate \$55.697 million in gross revenue and \$26.165 million in after tax profit in 1997. The asset base is \$256.593 million, less deferred taxes of \$66.272 million, resulting in a net asset base of \$190.321 million. The forecast rate of return on the net investment for 1997 is 13.75%.

3.7.2 Union initially proposed to maintain the rental program on a deferred tax accounting basis. In response to intervenor interrogatories, Union also filed evidence on the impact of changing the tax treatment of the rental equipment to a flow through methodology with `natural' amortization of the deferred tax balance which is more fully explained in Chapter 7.

ADR Settlement Agreement

3.7.3 The parties to the ADR Settlement Agreement agreed with the Companies' forecasts of Water Heater Rental Revenues. The ADR Settlement Agreement also stated that Union's "treating the water heater rental program on a flow-through basis resulted in a tax decrease and a \$2.3 million reduction in Union's 1997 revenue requirement".

3.7.4 Pollution Probe indicated in the ADR Settlement Agreement that it intended to argue that Union's "additional revenue" should not be offset against the overall test year revenue requirement, but should be streamed to the rental program to reduce water heater rental rates.

Positions of the Parties

3.7.5 Union submitted that the application of the tax decrease to reduce the 1997 revenue requirement was appropriate since 86% of residential customers rent their equipment. In any event, Union noted that the Board does not approve rental rates and further submitted that a reduction in rental rates in 1997 followed by increases in future years would cause confusion in the market.

3.7.6 OCAP submitted that the $2.3 million reduction in Union's 1997 revenue requirement should be applied to reduce rental charges, based on the principle that any excess rental revenues should go to the customers who are overpaying. A further reason is that, in OCAP's view, it is in Union's interest to raise rental rates prior to separation of the water heater rental business to maximize the profit for its non-utility affiliate. OCAP argued that for these reasons, the Board should keep rental rates as low as possible at this time.

Board Findings

3.7.7 Water heater rentals are not monopoly utility services and the Board does not set water heater rental rates. The Board limits its approval to a review of the rate of return of the Companies' ancillary programs including the rental program, and the non-utility eliminations from Cost of Service, to ensure that regulated activities are not subsidizing non-regulated activities.

3.7.8 The Board notes that Union is planning to move its rental program outside the regulated Utility in 1998 and to return this program to deferred tax accounting at that time. The Board agrees with Union that a one year reduction in rental rates, due to a temporary change in tax accounting, followed by increases, is not appropriate and that the customers who rent water heaters will receive a portion of the benefit from the reduction in the 1997 revenue requirement.

3.7.9 The Board notes that the use of flow-through taxes will result in a reduction of $2.203 million to the deferred tax component Union's income tax allowance for fiscal 1997, and a corresponding reduction of $1.102 million to the Union's 1997 accumulated deferred income taxes based on an average of monthly averages. The

Board finds that these adjustments should be directed towards reducing Union's overall revenue requirement for fiscal 1997.

COST OF SERVICE

Each Company's proposed test year Cost of Service results from costs related to the allowed return on the 1997 Rate Base for the regulated Utility, plus a number of major categories of planned direct Utility Cost of Service expenses including:

- O&M expense;
- Depreciation and Amortization;
- Gas Costs; and
- Property and other taxes.

In addition, the Companies must remove costs associated with non-utility eliminations from the test year Cost of Service, before seeking Board approval of the Utility Cost of Service and resulting revenue sufficiency or deficiency.

3.8 OPERATIONS AND MAINTENANCE EXPENSE

3.8.1 In 1994 Union and Centra requested Board approval to enter into a Shared Services arrangement between the Companies to provide a number of services on a common basis. The services to be shared included: distribution operations and engineering, marketing, finance and administration, IT, Regulatory, Gas Supply, Human Resources ("HR"), Audit, Legal and a common Executive. Board approval was granted in E.B.O. 177-06/E.B.R.L.G. 34-12 to proceed with the implementation of the Shared Services Plan.

3.8.2 Union and Centra filed a pooled O&M expense forecast for the test year, reflecting the integrated nature of most departments. However, both Companies are still required to report their costs separately for both regulatory and legal entity purposes. In order to apportion the costs of the Shared Service departments and resources, the Companies engaged Arthur Andersen to review the cost allocation study prepared by the Companies. Arthur Andersen used the cost driver methodology, which had been previously presented to the Board in E.B.R.O. 486 for allocating utility and non-utility costs at Union.

3.8.3 The cost driver methodology mirrors traditional cost allocation except that it uses common parameters such as head count, investment, rate base etc., to allocate costs between either regulated and unregulated activities, or between affiliates or Strategic Business Units ("SBUs"). The cost driver methodology operates on the approach that there is a strong causal link between the costs of activities being undertaken and the affiliates or business units that are being provided services through the activities. It involves identification of the underlying causes of costs, pooling of costs which occur in a similar manner and determination of the appropriate allocation factor (cost driver) to allow ongoing allocations with only minor refinements from year to year.

3.8.4 The Companies' combined O&M Expenses as forecast for the 1997 test year and a comparison with prior years is shown in Table 3.2.

Table 3.2: Combined Union and Centra O&M Expense, 1995 - 1997

	1997			1996	1995
Particulars	Gross cost	Annual (1) Shared Services Saving	Companies Net Cost	Bridge Year Forecast	Historic Year Actual
			($000's)		
Storage & Transportation Services					
Major Industrial Markets	2,625		2,625	2,410	2,208
S&T (ex Joint ventures)	2,241		2,241	2,214	2,149
Joint Ventures	4,331		4,331	4,330	4,068
Compressor Fuel	(641)		(641)	(549)	(3,116)
Total ST&S	**8,556**	**0**	**8,556**	**8,405**	**5,309**
Distribution Business					
Marketing	16,656	771	15,885	15,856	18,723
Distribution Operations	136,921	691	136,230	133,142	126,800
Total ST&S	**153,577**	**1,462**	**152,115**	**148,998**	**145,523**
Resource Groups					
Admin/Finance	33,096	1,069	32,027	32,851	33,976
Audit Services	951	70	881	831	662
Engineering	18,163	489	17,674	17,373	18,358
Environmental/DSM	3,670		3,670	2,973	595
Gas Supply	4,817		4,817	4,833	5,017
Gas Supply Operations	14,296	926	13,370	14,118	14,560
Govt & Media Relations	1,043		1,043	1,010	664
Human Resources	44,120	2,163	41,957	42,304	41,842
Information Technology	22,144	2,206	19,938	19,562	20,003
Legal	2,218	17	2,201	2,306	1,845
Regulatory	8,669	1,265	7,404	6,575	7,712
Risk & Claims	6,675		6,675	6,103	4,073
Senior Management (Executive)	9,138	893	8,245	8,041	6,506
Total Resource Groups	**169,000**	**9,098**	**160,502**	**158,880**	**155,813**
Financing Program	(1,215)		(1,215)	0	0
Capitalization (4)	(25,425)		(25,425)	(26,018)	(27,962)
Donations					0
Customer Deposit Interest	48		48	48	44
TOTAL O&M EXPENSE	**304,541**	**10,560 (1)**	**294,581 (3)**	**290,313**	**278,727 (2)**

NOTES:
(1) Excludes non O&M costs of $3,211
(2) Board approved $285.8 gross $283.9 net
(3) Company subsequently revised figure to $294.601 million
(4) Excludes indirect and overhead capitalized expenses relating to construction projects.

3.8.5 The Companies, in their updated prefiled evidence, forecast their 1997 combined O&M expenses as $294.601 million after a Shared Services saving of $10.56 million. The forecast 1997 figure and bridge year 1996 figure include a provision of $5.2 million for payment of Westcoast Corporate Centre Charges which is addressed in Chapter 5 of this Decision.

3.8.6 The Companies indicated that on a pooled basis, the 1997 forecast O&M expenses represented an increase of only 1.5% over the 1996 budget and 3.8% over the 1995 Board-approved budget. The Companies forecast wage increases in 1997 of 2.5% for non-union salaried employees and 1.5% for all unionized positions. The Companies indicated that this was done by targeting increases for all costs at or below inflation. (Inflation target for customer driven operating costs, with a zero percent increase for all other costs). The Companies provided a number of productivity indices comparing operating costs to the number of customers and volume throughput.

3.8.7 The Companies used the cost driver approach developed by Arthur Andersen to allocate the 1996 and 1997 pooled O&M expenses between Union and Centra. The cost drivers employed included head count, number of customers, earnings on common equity, rate base, distribution volumes and capital requisitions. The application of these cost drivers resulted in an approximate overall 75/25 split of O&M expenses between Union and Centra.

3.8.8 The Companies proposed that the total combined O&M expenses be allocated, on the basis of the cost driver study, $221.195 million and $73.406 million to the 1997 Cost of Service of Union and Centra respectively .

ADR Settlement Agreement

3.8.9 The following parties participated in the ADR Settlement Agreement with regard to O&M expenses: Board Staff, CAC, IGUA, OCAP, NOVA, ONA, NRG, ECNG, Energy Probe, HVAC, Kitchener, and Schools.

3.8.10 Given the parties' agreement that the MFPs should be retained within the Utilities for the test year, the parties agreed that the O&M budget should be increased by $1.2

million to reflect the added O&M expenditures relating to those programs, making the total budget $295.8 million.

3.8.11 The parties agreed that the pooled O&M budget should be reduced by $2.4 million to $293.4 million and that this reduction should be split on a 27/73 basis between Centra and Union to reflect the overall apportionment under the cost driver methodology. With this reduction, the increase in the 1997 O&M budget is 1.1% over the 1996 budget and 3.4% over the 1995 Board-approved O&M budget.

3.8.12 The Companies committed to achieving the agreed reductions by examining the areas of insurance expense, benefit costs, employee relocation and related expenses, regulatory, hearing costs and other general reductions. The Companies committed to managing the reduction through increased productivity or elimination of business plans, with due consideration for the following principles:

(i) system integrity, reliability and safety will not be compromised;
(ii) customer service levels will not be materially affected; and
(iii) employees will be fairly treated and will receive competitive compensation.

3.8.13 The parties agreed not to engage in a review of productivity data given the Companies' current restructuring plans. The Companies agreed to revisit the issue of productivity targets once (any) business reorganization was complete. Pollution Probe reserved its right to pursue further O&M reductions through the exclusion of natural gas fireplace sales and marketing expenses.

3.8.14 The parties also agreed that the issue of the Westcoast Corporate Centre Charges should be examined before the Board and that any change in the amount of those charges would be separate from, and incremental to, the agreed upon O&M reductions.

3.9 OVERHEAD CAPITALIZATION PRACTICES

3.9.1 Union and Centra requested the Board to accept changes in its O&M expense capitalization methodology and the related impacts for 1997. Union and Centra currently apply different methodologies. The methodologies include elements of formula based, time sheet based and time estimate approaches. Union and Centra commissioned Arthur Andersen to review the capitalization practices of both Companies and to devise a consistent methodology for use by both.

3.9.2 The consultant recommended that the Companies adopt a cost driver approach. The proposed cost driver approach allocates costs between business units based on a volumetric measure, or other causal linkage, between specific types of expenses or activities and the business units. The cost driver approach is based on the principle that all costs of an activity, whether they be direct costs, or overhead costs should be included in the activity cost pool which is allocated by a cost driver to capitalization and capital projects. The Companies stated that the cost driver methodology was consistent with the Board's Uniform System of Accounts Regulation 245/66 and with generally accepted accounting principles and, like the existing methodologies used by Centra and Union, is based on full absorption costing.

3.9.3 The Companies stated that, since O&M expenses are now managed on a pooled basis for Union and Centra, the capitalization methodology must be consistent between the Companies and with the allocation of costs related to Shared Services and non-utility operations.

3.9.4 The Companies presented the results of applying the cost driver methodology for O&M capitalization for 1997 and a comparison of the results from using the existing methodology. For Union the O&M capitalized in 1997 with the new methodology was $26.473 million compared with $26.524 million using the existing methodology. For Centra the results were $19.387 with the new methodology and $18.174 with the existing methodology. The combined O&M capitalization of $45.068 million includes $20.435 million of direct and indirect costs which have been reflected in O&M expenses on a net basis, and the $25.425 million listed as capitalization in Table 3.2 of this Decision.

3.9.5 The Companies provided a brief history that indicated that actual and forecast capitalized O&M, as a ratio of capital spending, for Union in the period 1993 to 1997 was between 0.112 and 0.123; for Centra the range was 0.175 to 0.234.

3.9.6 The consultant commented that an important factor that differentiates the amount of O&M expenses capitalized by each company, is that Union contracts out most of its construction projects, whereas Centra constructs most of its capital projects with its own personnel. Therefore it is reasonable to expect a larger proportion of Centra's O&M budget will be capitalized.

3.9.7 The consultant stated that "the cost driver approach to capitalization is especially useful in a company which has a shared services environment". The consultant also noted that "it is essential that the two Utilities update their activity analysis each year, in order to improve on the specific volume measures which serve as cost drivers".

ADR Settlement Agreement

3.9.8 The parties to the discussion of this issue were: Kitchener, NOVA, ONA, Board Staff, CAC, ECNG, Energy Probe, NRG, IGUA,and OCAP.

3.9.9 The ADR Agreement stated:

> *The parties agreed that the new capitalization methodology proposed for Union and Centra should be accepted, subject to the Companies' commitment to file the ratio of capitalized overhead to total capital on a comparative basis in the next rates case, in order to monitor the overall level of capitalized expenses. The evidence indicates that the change in the overhead capitalization methodology will not materially affect the total amount of overheads to be capitalized, but better identifies the areas within the Companies where capitalized overhead costs exist.*

3.10 SHARED SERVICES PLAN

3.10.1 The Companies' final Shared Services Plan was approved as part of the Board's Decisions in E.B.R.O. 486 (Union) and E.B.R.O. 489 (Centra). The final plan forecast Shared Services savings and revenue enhancements of $4.376 million, $7.511 million and $13.502 million in the years 1995, 1996 and 1997 respectively. One time implementation costs of $11.348 million to be amortized over 3 years were also approved. The Board also approved the continuation of the One-Time Shared Services Integration Cost Deferral Accounts (Union Account No.179-36, Centra Account No. 179-94) and establishment of the Incremental Shared Services Impacts Deferral Accounts (Union Account No. 179-40, Centra Account No. 179-96) to record savings in 1996 and 1997.

3.10.2 In their prefiled evidence the Companies updated the results of the Shared Services Plan, provided the previously noted cost driver study for allocation of combined O&M expenses, including Shared Services savings and costs, and proposed the disposition and closing of the deferral accounts. They also provided the previously discussed O&M capitalization study for the Companies' 1997 test year.

3.10.3 The Companies' evidence indicated that Shared Services "savings" were being achieved and the forecast for the test year of $13.771 million was slightly above target. The one time costs were lower than forecast at $10.533 million. This figure was subsequently amended to $9.599 million.

3.10.4 The annualized capital cost savings were now forecast to be $755,000, substantially less than the original forecast of $1.82 million.

3.10.5 The deferral account balances at the end of 1996 were forecast to be $1.893 million (Union) and $1.393 million (Centra).

ADR Settlement Agreement

3.10.6 In the ADR Settlement process Kitchener, Schools, NOVA, ONA, Board Staff, CAC, ECNG, Energy Probe, NRG, IGUA and OCAP reviewed the status of the Shared

Services Plan, intra-company allocations and the Shared Service deferral accounts of the Companies.

3.10.7 The parties agreed that the Companies' evidence and proposals in connection with Shared Services should be accepted. The parties further agreed that the Shared Services deferral accounts should be closed, subject only to an examination of the balances in those accounts. The accounts to be closed in the case of Union are the One-Time Shared Services Integration Cost Deferral Account and associated interest (Account Nos. 179-36 and 179-37), as well as the Incremental Shared Services Impacts Deferral Account (Account No. 179-40). The accounts to be closed in the case of Centra are the One-Time Shared Services Integration Cost Deferral Account (Account No. 179-94), as well as the Incremental Shared Services Impacts Deferral Account (Account No. 179-96).

3.11 AFFILIATE TRANSACTIONS AND NON-UTILITY ELIMINATIONS

3.11.1 In this hearing the Companies requested approval of a number of affiliate transactions. The largest transaction identified by the Companies is the payment to Westcoast of certain charges related to the Westcoast Corporate Centre which is discussed separately in Chapter 5 of this Decision.

3.11.2 The Companies also requested Board approval of certain ongoing affiliate transactions and in particular:

- Union's continued holding of certain Westcoast preference shares until October 1997 when they are to be redeemed;
- Union's continued involvement in partnership with St. Clair Pipelines (1996) Limited ("SCPL") in the Ford Cogeneration Plant Partnership which operates a cogeneration project at the Ford plant in Windsor, Ontario;
- the transfer of certain tax liabilities related to preference share dividends from Westcoast to Union and Centra in accordance with provisions of the Income Tax Act; and
- payment to Centra of management fees related to Centra's management of two small pipeline affiliates.

3.11.3 The Companies also requested that the Board grant blanket approval to S&T transactions and gas supply transactions that may occur between the Companies and their affiliates in the normal course of business. The blanket approval of such transactions had been granted in the past; however there were conditions on the approval requiring the Companies to provide information on each transaction to the Energy Returns Officer ("ERO") at the time it occurred and evidence in the rate case filing on all transactions since the last rate case filing. The Companies requested that they be required only to file information with the ERO and not to report publicly because of the commercial sensitivity of the information.

3.11.4 As indicated above, the cost driver methodology was originally used in the case of Union for the purposes of allocating 1996 O&M expenses between utility and non-utility functions including non-regulated, non-asset based S&T Services by Westcoast Gas Services Inc. ("WGSI") and other activities of affiliate companies including St. Clair Pipelines (1996) Ltd., Union Gas Power Partnership, Trillium USA, and Union Gas Services Ltd. The Companies requested approval of the same type of allocation of utility and non-utility costs for the 1997 test year. The Companies originally forecast approximately $2 million in non-utility eliminations from O&M expenses. This number was subsequently reduced by $650,000 to reflect the reorganization of Union's S&T department to remove certain non-utility marketing functions which were to be relocated in WGSI's new operations, leaving certain fixed costs that would now be related to utility activities only.

ADR Settlement Agreement

3.11.5 The following parties participated in the discussion of affiliate transactions: Kitchener, Schools, OCAP, Board Staff, CAC, NOVA, ECNG, Energy Probe, NRG, and IGUA. The parties accepted the Companies' evidence with regard to Union's investment in preference shares of Westcoast, Union's continued participation in the Ford Cogeneration Plant Partnership, the tax liability transfer from Westcoast to Union and Centra and payment of management fees to Centra by certain affiliates. The parties also agreed to accept the blanket approval request by Union and Centra for S&T and gas supply transactions with affiliates on the condition that the Companies continue to file details concerning the transactions in the rate cases.

3.11.6 The following parties accepted the Companies' evidence with respect to the quantum of non-utility eliminations from the 1997 O&M expenses proposed by the Companies: Kitchener, Schools, NOVA, ECNG, Board Staff, ONA, Energy Probe, Enron, IGUA, OCAP and Pollution Probe. The parties also agreed that the Companies should report in the next rates case on the costs associated with determining, allocating and monitoring cost allocations for non-utility activities.

3.11.7 There was no agreement with respect to Westcoast Corporate Centre Charges.

Board Findings on O&M Expense

3.11.8 The Board finds that the Companies' prefiled evidence and the ADR Settlement Agreement provides a sufficient evidentiary base and indication of the positions of the parties on the following Shared Services issues:

- Union and Centra O&M expenses, excluding Westcoast affiliate transactions and Fireplace Marketing expense;
- Overhead Capitalization Practices;
- Shared Services Plan;
- Affiliate transactions and non-utility eliminations, excluding Westcoast affiliate transactions.

Union and Centra O&M expense, excluding Westcoast affiliate transactions and Fireplace Marketing expense

3.11.9 The Board finds the $2.4 million reduction of O&M expenses supported by the ADR Settlement Agreement acceptable for ratemaking purposes, and approves the apportionment of 27/73 between Centra and Union as provided in the cost driver study. As a result of this reduction, Centra's O&M Expenses have been reduced by $648,000 and Union's O&M Expenses have been reduced by $1,752,000.

3.11.10 As discussed under the heading Ancillary Programs - Rental and Financing Programs, O&M expenses resulting from the inclusion of the MFP in Utility operations has increased O&M Expenses by $358,000 for Centra and $857,000 for Union.

3.11.11 The Board approves the Companies' combined O&M budget and its allocation to Union and Centra as agreed in the ADR Settlement Agreement, subject to adjustments resulting from its Findings on the DSM Program in Chapter 4, Westcoast Corporate Centre Charges in Chapter 5 and the inter-affiliate transaction related to the Union Energy Catalogue later in this Chapter.

Overhead Capitalization Practices

3.11.12 The Board accepts the use of a cost driver approach for the determination of the capitalization of O&M expenses for Centra and Union for the 1997 test year.

3.11.13 However the Board has some concern regarding the increase in the amount of O&M expenses to be capitalized in Centra under the new methodology, when compared to the existing methodology. The Board also notes the advice of the consultant that it is "essential" that the Utilities update their activity analysis each year to improve on the volume measures which serve as cost drivers. The Board also concurs with the ADR Settlement Agreement condition that the Companies file comparative ratios on the level of capitalized overhead to overall capital spending.

3.11.14 The Board directs the Companies to present a report at their next rates hearings on the update of the activity analysis; comparative statistics that will enable the Board to judge whether there is a systemic shift with regard to the level of capitalization of O&M expenses as a result of the change in capitalization methodology; and a succinct presentation that will enable parties to check that the choice and use of cost drivers at different stages of the allocation of O&M expenses is consistent.

Shared Services Plan

3.11.15 The Board finds that the Companies' evidence and the ADR Settlement Agreement provide sufficient evidence for the Board to accept the Companies' updates on the Shared Services Plan and to order the closure of the Shared Services Deferral Accounts and disposition of the balances as proposed by the Companies. The details of this disposition are dealt with in Chapter 8 of this Decision.

Affiliate Transactions and Non-Utility Eliminations

3.11.16 As noted above, the Companies originally forecast approximately $2 million in non-utility eliminations from the 1997 O&M budget. This number was subsequently reduced by $650,000 to reflect the reorganization of Union's S&T department. The parties to the ADR Settlement Agreement agreed to the Companies' revised figure.

3.11.17 The Board finds that for affiliate transactions involving St Clair Pipelines (1996) Limited, Union Gas Power Partnership, Trillium USA, Union Gas Services Ltd. and WGSI, Centra Pipelines Inc. and Centra Transmission Inc. the ADR Settlement Agreement provides a sufficient evidentiary basis and the Board approves these transactions for 1997.

3.11.18 The Board accepts $1.35 million as the figure for affiliate non-utility O&M eliminations in the 1997 test year.

3.11.19 The Board finds that the ADR Settlement Agreement on the blanket approval for affiliate S&T transactions is appropriate. However given the possible separation of the Companies' S&T Services, the Board directs that the maximum term of any contract remain as at present.

Other Cost of Service Expenses

3.11.20 The Board has examined the evidence adduced in the hearing and the written submissions of the parties in order to make additional Findings on the following hearing issues arising from the Companies' evidence and the ADR Settlement Agreement:

- Fireplace Marketing and Sales Expense; and
- Union Energy Catalogue.

3.12 FIREPLACE MARKETING AND SALES EXPENSE

3.12.1 Union and Centra currently offer sales and installation of natural gas fireplaces as part of their merchandise sales ancillary programs. The cost of fireplace marketing and promotion is budgeted at $450,000 for 1997.

3.12.2 In the ADR Settlement Agreement on Shared Services O&M expenses, Pollution Probe reserved the right to pursue whether the Companies' O&M budget should be further reduced by exclusion of some or all of the Companies' natural gas fireplace sales and marketing costs.

3.12.3 In its E.B.R.O. 489 Decision the Board observed that "*Centra could be more aggressive now in the promotion of the wise use of natural gas fireplaces"*. The Board also stated that it "*expects Centra to promote energy efficiency in its fireplace promotion advertising,*" and "*once new standards for natural gas fireplaces are approved and experience has been gained with them......Centra will move towards discontinuing the sales and marketing of lower efficiency fireplaces*". (para 4.6.11)

3.12.4 The Companies' evidence was that both Centra and Union are currently offering a full range of natural gas fireplaces in their merchandise sales programs without particular regard to the energy efficiency of the units. For 1997 they are forecasting 18,232 fireplace installations and a gas sales volume increase of 5.1 $10^6 m^3$.

3.12.5 The Companies stated that there was, as yet, no fireplace energy efficiency standard in place in Ontario or Canada and that its technical staff were active participants in the development of a draft national standard which was expected to be released for comment in 1997.

3.12.6 Pollution Probe provided evidence that a provisional draft fireplace efficiency standard was in place in British Columbia for the purpose of qualifying units as eligible for financial assistance under that province's Clean Choice Program. The Program's information sheets indicated that the Annual Fuel Utilization Efficiency ("AFUE") of gas space heaters ranged from -20% to +75%.

3.12.7 The Companies' witness stated that a draft Canadian Gas Association ("CGA") fireplace efficiency standard (CGA P4) has been under development since 1993 and, initially, the proposed test method suffered from problems of non-repeatability of the measured efficiencies. However after modification, the test method contained in the draft standard was found to produce an acceptable level of variation in the results obtained by two independent testing facilities.

3.12.8 The Companies indicated that they have a considerable amount of information on the efficiency of the 42 models of fireplace that they sell, but do not plan to provide this to customers until the CGA standard is finalized in 1998. The preliminary data indicate that 9 out of the 42 models are higher efficiency units, having an AFUE of 70% or greater.

Positions of the Parties

3.12.9 GEC submitted that, although the draft provisional standard in use in British Columbia is not final or legally enforceable, it has been used sufficiently in British Columbia for Union and Centra to require the testing and labelling of fireplaces sold through the Companies' merchandising programs. It further argued that the Companies should make available comparison lists, such as those available in B.C.

3.12.10 GEC submitted that the Board should direct the Companies to institute mandatory testing and labelling for all fireplaces that they sell, finance or otherwise promote and to make the energy efficiency rating and labelling prominent features in all Company advertising and displays.

3.12.11 Pollution Probe submitted that the Companies' fireplace sales will result in increased gas volumes which are 1.6 times the forecast 1997 DSM gas volume savings. The Companies' promotion literature claims that “All of Centra/ Union’s fireplaces are considered to be high efficiency with efficiencies ranging from 70%-79% based on literature provided by the manufacturer”. Pollution Probe noted that the Companies have admitted that only 9 out of 42 models meet this criterion.

3.12.12 Pollution Probe submitted that the Board's approval of the $450,000 fireplace sales promotion budget should be contingent upon the Companies' agreeing to:

! send a bill insert to all of their residential customers in the first quarter of 1997 informing them that:

- there is a wide variation in the energy efficiencies of gas fireplaces;
- the CGA has established a draft standard for measuring the efficiency of gas fireplaces; and
- Centra and Union will, upon request, provide a list of fireplaces and their efficiencies measured according to the draft CGA standard.

! sell only fireplaces whose CGA calculated efficiency is available; and

! Finance only fireplaces whose calculated energy efficiency is publicly available.

3.12.13 The Companies submitted that not only does a fireplace standard not exist, but it is clear that efficiency in isolation is not a complete measure, since efficiency is not related to energy loss. Union and Centra have limited power to force manufacturers to adhere to the draft CGA standard. Consequently, the Companies submitted that the sales and marketing budget for natural gas fireplaces should not be contingent on the conditions advanced by Pollution Probe. It was also the Companies' view that providing a list of fireplaces and energy ratings to customers was not advisable, until the CGA addresses the relationship between efficiency and energy loss.

Board Findings

3.12.14 The Board, while not agreeing with the specific remedies recommended by GEC and Pollution Probe, finds that there is merit in the Companies developing a plan to provide efficiency information to customers and to then market and promote higher efficiency gas fireplaces. The Board is cautious about using the term “high efficiency” in this context, since any space heater with a lower efficiency than the minimum furnace efficiency of 78% AFUE cannot, in the Board’s view, be considered "high efficiency".

3.12.15 The Board believes that it may be appropriate to promote and finance true high efficiency space heaters (>78% AFUE) as part of the Companies' DSM program, once such units are available and tested according to national standards.

3.12.16 The Board directs the Companies to develop and implement a consumer information and marketing plan for "higher efficiency" fireplaces and to report on this in their next rates cases. The costs of this plan are to be included as part of the $450,000 budget for fireplace sales and promotion in 1997.

3.12.17 In the interim, the Board expects the Companies to support efforts to develop a final CGA fireplace standard and a national labelling program under ENERGUIDE.

3.13 UNION ENERGY CATALOGUE

Background

3.13.1 During the hearing, the Board filed copies of two documents that had been brought to its attention by a Board Advisor: a catalogue entitled *Welcome Home*, distributed by Union Energy Inc., an affiliate of both Companies, and a document entitled *Backgrounder to the Union Energy Catalogue*. These documents had been provided by the Utilities to a Board Advisor while the hearing was in progress, at about the same time as the catalogue was mailed out to a selected segment of the public. In argument-in-chief, the Companies explained that the documents had been provided in this way “in the expectation and intent that the material in the catalogue and the backgrounder would be given to the Board, so that it would be aware of these developments”.

The Evidence

3.13.2 According to the Companies’ evidence, the publication of the catalogue was a pilot project which arose out of other Union/Centra marketing initiatives. In September, 1996, a decision was made that the catalogue should be handled by Union Energy Inc., rather than by the Utilities, because: the products involved were not solely gas-related; the distribution was to both gas consumers and other consumers; and it was judged that the risks associated with the enterprise were greater than the risks traditionally undertaken by the Utilities in their marketing programs.

3.13.3 The catalogue offers a number of products, some designed to improve efficiency of home energy use, some relating to home or auto safety, and others to convenience and comfort. A number of the items offered are also available through the Utilities' DSM program. Customers can order the items through a toll-free number, and may pay for them on their gas company account, on their credit card, or by cheque. In choosing the gas company's account, customers may choose to pay over 3 payments, provided their order totals more than $100. The pilot project was launched in time to capture pre-Christmas sales, and was to run until March 1997, when its success would be evaluated.

3.13.4 According to the Companies' evidence, the costs associated with the use of the Companies' billing system, both direct and indirect, total $155,000, with $80,000 to be recovered in 1996, and $75,000 to be recovered in 1997. The Companies' witness acknowledged that there were other items, such as the use of the Companies' corporate names and logos, which had not been included in the accounting for costs. No payment had been made for goodwill, although both Companies' names were used extensively in the catalogue, and possible billing through the Companies was an important aspect of the catalogue's offerings. Focus groups which provided data upon which the catalogue was developed were paid for by the Companies, not by Union Energy. Costs charged by the Companies to Union Energy were calculated at marginal, rather than fully allocated costs. Third party invoices were payable by Union Energy, but were billed to Union, and subsequently invoiced to Union Energy. It was acknowledged in cross-examination that consumer psychology created by the Companies' DSM programs provided part of the rationale for embarking on the catalogue program.

Positions of the Parties

3.13.5 In argument-in-chief, the Companies acknowledged that, on the part of "those charged with dealing with this pilot project there should have been more thought given to the impact of what was being done in the context of the agreements that had been reached amongst the parties in the ADR agreement and...the Board's concern for these matters...". In any event, the Companies submitted, matters such as cost allocation, revenue assessment, use of the corporate name, value of goodwill and related matters, should be examined at the next rates case, on the basis of proposals the Companies intend to develop for the Board's consideration at that time.

3.13.6 In the meantime, the Companies agreed that Union's 1997 Cost of Service be revised to reflect the revenues and costs forecast for the catalogue program in the amounts of $15,000 in direct and indirect costs, and a forecast $60,000 recovery for billing charges.

3.13.7 Board Staff submitted that the Company had used “a very conservative approach in assigning affiliate transaction costs to the Union Energy catalogue", and that the catalogue program should have triggered the affiliate transaction provisions in the Companies’ Undertakings. Board Staff argued that the Companies should be directed to file in the next rates case, detailed financial statements accounting, on a fully allocated basis, for all aspects of the affiliate transaction between Union Energy and the Companies, including allowances for such items as the use of corporate names and logos, goodwill, intellectual property, payments for information gained from focus groups, and third party billing through the regulated Utilities. In Board Staff’s view, the accounting should cover the period from the catalogue’s inception in spring 1996, to the future test year, and should include information concerning the sale of items through the catalogue which might have been purchased by customers “from Centra/Union’s DSM program".

3.13.8 Noting that parties to the ADR Settlement Agreement had accepted the Company’s evidence relating to the residential programs of the DSM Plan without knowledge of the catalogue, Board Staff submitted that the catalogue would “cannibalize portions of the residential DSM program”, diminishing the market available for residential DSM sales in fiscal 1997. They argued further that the affiliate, Union Energy is “free-riding” on the fiscal 1997 DSM plan, and that, following the provision of the detailed accounting at the next rates case, “financial adjustments should be made to Centra/Union’s DSM budget to reflect the true costs of the assistance Centra/Union provided to Union Energy Inc."

3.13.9 GEC noted the adjustment with respect to the 1997 revenue agreed to by the Companies in argument, and submitted that this adjustment is appropriate; GEC also suggested that it may be appropriate to reopen 1996 rates to recognize the $80,000 revenue from these affiliate transactions in that year. In addition, GEC expressed concern that the Board’s attention was drawn to these transactions fortuitously, and submitted that there is considerable potential for inequitable treatment of ratepayers which may not be prevented by the current Undertakings. GEC requested that the Board "underline the need for an examination of the adequacy of the Undertakings and of cost allocation practices to be addressed fully in upcoming cases dealing with corporate structure."

3.13.10 IGUA accepted the acknowledgment by the Companies that the catalogue activity was undertaken without regard for the fact that parties to the ADR settlement process had agreed that principles relating to ancillary activities would be addressed in the next rates case. The Companies' proposed revision to the 1997 Cost of Service to reflect this was acceptable to IGUA.

3.13.11 OCAP expressed concern that cross-subsidies may occur through activities between the Utilities and their affiliates, and stated that it intends to address these concerns in the next main rates case.

Board Findings

3.13.12 The Board is concerned that the implementation of the catalogue program was not brought to its attention more directly by the Company through the hearing process. Although information was provided belatedly, through a Board Advisor, this mechanism of providing information which may be necessary to the Board's adjudication is unsatisfactory, both for the Board and other parties to the regulatory process. The Board would expect, as a matter of course, voluntary formal disclosure by the Companies of a matter which might be relevant to an application before the Board.

3.13.13 The Board agrees with Board Staff and others that the assignment of costs to the catalogue program by the Companies was very conservative, and that, had allowances been made for other items which were not included in the costing, and the fact that Union procured many of the production services, the affiliate transaction provisions of the Undertakings would have been triggered. The Board notes, in particular, the modest costs estimated for the catalogue in comparison with those estimated by the Companies for producing a Customer Information Package ("CIP") to provide customer information about the proposed ABC Service.

3.13.14 The Board directs that the Companies present a full accounting for the costs and revenues from the catalogue program at the next rates hearing.

3.13.15 The Board notes that, while the DSM Plan does provide customers with the option of purchasing energy saving devices through the Companies, and through other agents such as the Green Communities, its effect will also be to encourage customers to make such purchases, when they choose to do so, through other commercial outlets. In a way, all merchants of these products benefit from the “consumer psychology” created by the DSM program.

3.13.16 In the circumstances, the Board is not persuaded that the offering of energy saving devices through the Union Energy catalogue will harm the relevant DSM programs; in fact, it is possible that customers may be more persuaded by the presentation in the catalogue than they had been by other DSM publicity, and may therefore make additional energy efficiency purchases, resulting in more gas savings. In any case, it did not appear to the Board that the 1997 DSM Plan preferentially promoted the purchase of energy saving devices from Union Energy.

3.13.17 The Board finds that Union's 1997 cost of service should be reduced by $15,000 indirect costs and $60,000 for billing costs related to the Union Energy Catalogue.

3.13.18 The Board notes the agreement of all parties to the ADR discussions that cost allocation studies of non-utility affiliate transactions, such as the catalogue, and of ancillary programs, such as the rental and MFPs, will be presented at the next rates case.

3.14 OVERALL FINDINGS ON 1997 UTILITY INCOME

3.14.1 The Board has also made findings on the following matters related to the Companies' Utility Income:

- Demand Side Management (O&M) - Chapter 4;
- Affiliate Transactions - Westcoast Corporate Centre Charges - (O&M) Chapter 5; and
- Cost of Gas - Chapter 6.

There has been no change to the forecast Utility Income as a result of the Board's findings for DSM or the Cost of Gas. The Board has however reduced the allowed O&M expenses as a result of its review of the appropriateness of the Westcoast Corporate Centre Charges. The Board has reduced Union's O&M expenses by $2.272 million, and Centra's O&M expenses by $0.675 million as a result of these findings.

3.14.2 Certain components of Utility Income including property and capital taxes, income taxes, and depreciation were not issues of any particular significance in this proceeding. The Board has reviewed the evidence and ADR Settlement Agreement in these areas, and finds that the Companies' proposals are acceptable. The Board has however adjusted these items to reflect the specific impact of findings in related areas on these expense categories. In addition, the Board notes that the ADR Settlement Agreement states that the Companies will review the methodology used to forecast property taxes and report on the review at the next rates case. The Board expects the Companies to fulfil that agreement.

3.14.3 The financial impacts related to specific Board findings have been included with those findings, rather than in this summary.

3.14.4 For Centra, Appendix E serves as a summary of the forecast income and expense components used to derive the Company's forecast 1997 Utility Income of $58.438 million, the specific impact of adjustments to these components resulting from the ADR Settlement Agreement and adjustments made by the Board in this Decision and the Interim Rate Orders issued December 24, 1996 and February 17, 1997. Centra's Board-approved forecast Utility Income for 1997 is $72.317 million.

3.14.5 For Union, Appendix A serves the same purpose, and shows that the ADR Settlement Agreement and Board findings in this Decision have resulted in a $30.868 million increase to forecast 1997 Utility Income from the $206.906 proposed by the Company. Union's Board-approved forecast of Utility Income for 1997 is $237.774 million.

4. DEMAND SIDE MANAGEMENT PROGRAM

4.1 BACKGROUND

4.1.1 In its E.B.O. 169-III Report dated July 23, 1993, the Board directed the three major gas utilities in Ontario to develop formal DSM plans according to guidelines set out in that Report, and to present these to the Board as part of their subsequent rate cases. Centra received Board approval in E.B.R.O. 489 of its first plan in March 1995, but the Board found in E.B.R.O. 486 that the first plan filed by Union, for fiscal 1996, had many shortcomings. Early in 1995 Union and Centra determined that future DSM plans of the two Companies would be combined as a Shared Services activity, and in October 1995, a new department head was named to be responsible for DSM planning.

4.2 CONSULTATIVE PROCESS

4.2.1 Early in calendar 1996, work began on the Companies' combined DSM Plan. The Companies developed a set of principles and objectives, identified individual DSM measures and tested their cost effectiveness. They then grouped the measures by market area, and developed program concepts and ultimately programs, to achieve the planned gas savings in each of the target markets. The Companies set up a consultative process involving a number of interested parties. The consultation meetings took place during the first half of 1996. The purpose of the consultation was to discuss the principles and objectives that the Companies were proposing, the design of the programs, the screening mechanisms, and other aspects of the Companies' DSM proposals.

4.3 PRINCIPLES AND OBJECTIVES

4.3.1 The following DSM principles and objectives resulted from internal discussions within the Companies' management, prior rate decisions for both Companies, and the discussions in the consultative process:

Principles

1. *Facilitate the efficient use of gas by customers in each market segment by developing and delivering customer-valued DSM programs.*

2. *Foster and support DSM innovation and experimentation.*

3. *Aspire towards permanent market transformation where customer attitudes and actions are favourable to DSM and energy conservation.*

4. *The Companies' DSM efforts will not result in an undue rate impact on customers.*

5. *Employ a user pay principle, subject to not unduly restricting program participation.*

Objectives

1. *Develop and implement a societal cost effective portfolio of DSM programs that reduces natural gas consumption and follows the guidelines in E.B.O. 169-III. These programs will:*

   C *fulfill customer needs as determined through surveys, focus groups, and other customer feedback;*

- *identify and address market barriers within each sector by developing a DSM portfolio with a broad scope, including information programs, financing and rental programs, and service programs;*

- *to the degree possible and practical, ensure that lost opportunities are captured;*

- *allocate to, and appropriately recover DSM program costs and revenue impacts from, the individual rate classes within each Company.*

2. *Conduct effective monitoring and evaluation for each program to provide measurable feedback on customer participation, customer satisfaction, program delivery mechanisms, load impacts and emissions reductions.*

3. *Build upon existing expertise and reduce duplication of efforts by investigating the opportunities to partner with other stakeholders.*

4. *Ensure open dialogue with interested parties through, but not limited by, the consultative process.*

5. *Recognize and consider, where possible, the needs of special groups such as low income customers.*

6. *Perform extensive review of gas DSM in other jurisdictions in order to learn from the experience of others.*

4.4 THE COMPANIES' COMBINED DSM PLAN

4.4.1 The following is a brief description of the eight programs which were approved by management for the initial five year DSM Plan period (1997-2002). The forecast costs for the 1997 DSM programs are taken from a detailed breakdown provided by the Companies in response to a Board Staff interrogatory, and do not include costs for market support and research. The overall 1997 DSM Plan costs and their allocation between Union and Centra can be found in Table 9.1.

1. New Home Construction

Objective: to encourage builders of single family homes to install higher efficiency equipment and improve building designs by preconditioning the market so customers expect energy efficient housing, thus creating a long-term demand for efficiency measures that builders are currently unwilling to install.

The program which is forecast to cost $50,000 in 1997 includes customer education, seminars for builders and manufacturers, increases in the average efficiency level of water heaters included in the rental program, brochures targeted at new home buyers, and support for the raising of the R2000 standard. The program is forecast to result in gas savings of 1.8 10^6m^3 over a 5 year period.

2. Home Equipment Replacement

Objective: to encourage the uptake of higher efficiency equipment during equipment replacement or conversion decisions, by creating consumer preference for renting and/or purchasing cost effective, higher efficiency products, educating customers on the cost and benefits of high efficiency equipment, and supporting dealers in marketing higher efficiency equipment.

The program will include: preferential financing, rebates and discounts, and rental programs for high efficiency furnaces and water heaters, where appropriate; the promotion of higher efficiency water and space heating equipment and programmable thermostats; discounted tank rental rates for high efficiency water heaters; an increase in the efficiency levels for water heaters in the rental program; and cooperative advertising and promotions to contractors to assist them in the sale of energy efficiency equipment. The program is expected to result in gas savings of 9.9 10^6m^3 over a five year period. The estimated program cost in 1997 is $580,000.

3. Home Retrofit

Objective: to encourage customers to take action on gas saving measures that are discretionary in nature, through broadening and optimizing the use of various delivery channels to market those measures, with targeted emphasis on customers who are undertaking home renovations.

The program will include the promotion of the installation of gas saving measures such as low flow shower heads, programmable thermostats, water heater blankets, insulation, etc. through participating Green Communities [1], Centra/Union equipment dealers and service operators, and direct merchandising. Special efforts will be made to reach low income customers through communications via social agencies and non-profit housing and related associations. Program cost is forecast to be $465,000 in 1997. Forecast gas savings are estimated to be 4.7 $10^6 m^3$ over a 5 year period.

4. New Building Construction (Institutional, Commercial and Industrial) ("ICI")

Objective: to encourage developers, building designers and specifiers to design and build energy efficiency into new building design, equipment, and system specifications by pursuing market transformation in new building design processes. The program, in co-operation with Consumers' Gas' Energy Efficient New Building Design Program, will apply to new industrial, commercial and institutional buildings.

The program will include a program of education for developers, building owners, anchor tenants, architects and consulting engineers, contractors and municipal planning officials. Energy efficient designs and buildings will be showcased, and a project working with architects and engineers to facilitate energy efficient building designs will be initiated. Local seminars will also be held for architects, design engineers, and municipal building officials on the current building code standards relating to energy conservation. Costs forecast for 1997 are $150,000. Gas savings have not been estimated.

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1. Green Communities are non-profit organizations within communities, originally set up and funded by the provincial government to promote community based environmental initiatives, including those relating to energy efficiency and recycling. Green Communities are now required to raise their own funds.

5. Building Equipment Replacement (ICI)

Objective: to encourage the uptake of higher efficiency equipment during equipment replacement or conversion decisions, by creating a preference among owners and managers of small buildings who can replace equipment without technical support by renting and/or purchasing higher efficiency products which are cost effective.

The program will include general and targeted promotion of high efficiency furnaces, water heaters and programmable thermostats. Preferential financing and discounted rental rates will be available to encourage the choice of higher efficiency equipment. Cooperative advertising and promotional materials would be provided for dealers, and Union will continue to sell energy saving equipment through direct merchandising. The program is forecast to yield gas savings of 1.4 $10^6 m^3$ over a 5 year period; 1997 costs are forecast at $300,000.

6. Building Retrofit (ICI)

Objective: To encourage building owners and managers to include energy efficiency in their building renewal plans or to pursue energy efficiency retrofits by linking Centra/Union customers with solutions such as Energy Service Companies ("ESCOs"), Green Community Network, HVAC contractors, or any other energy management firms. At the same time, the Companies will better equip these delivery channels to market and install high efficiency gas equipment as part of their overall product/service mix.

The program will include seminars for engineers and contractors, and programs to encourage building owners and managers to consult with energy management firms. High efficiency procurement for water heaters, discounted rental rates, and promotion and education will also be included. Five year forecast gas savings are 4.4 $10^6 m^3$, 1997 forecast costs are $350,000.

7. Agriculture

Objective: To encourage uptake of higher efficiency equipment in the agricultural market by educating customers on gas saving measures and mitigating the barrier of high capital costs.

The program will include targeted information advising agricultural customers of cost effective gas saving measures, such as infrared heating, grain drying, high efficiency boilers, and heat recovery from refrigeration, and preferential financing for energy efficient equipment will be provided. Assistance in training Green Community staff on measures in the agricultural sector is another feature. Five year forecast gas savings are 0.52 $10^6 m^3$; 1997 forecast costs are $50,000.

8. Industrial Process Improvements

Objective: To help customers improve their competitiveness through the implementation of energy savings projects which reduce utility bills. This will be done by helping customers analyze specific energy saving projects, prepare business cases, conduct pilot projects and monitor results.

The target audience consists of industrial plant managers and plant engineers, industrial company executives, consulting engineers, contractors and manufacturers. Energy performance testing, gas technology seminars, gas flow metering and custom gas improvements are included in the program.

While industrial plants account for more than 50% of the Companies' gas sales, a large amount of industrial use is concentrated in boilers and steam systems. Industrial process improvement requires custom engineered solutions taking plant and production line specifics into account. Improvements may benefit the environment, as well as increasing productivity and product quality. Estimated gas savings from the program are 43 $10^6 m^3$ over a 5 year period. Forecast costs for 1997 are $455,000.

4.4.2 According to the Companies' prefiled evidence, the eight comprehensive programs incorporated into the 1997 DSM Plan were forecast to save 614 10^6m^3 of gas and achieve net benefits of $76.6 million (NPV) over the full life of the DSM measures installed. Greenhouse gas emissions would be reduced by 1.3 million tonnes, resulting in savings of $35.4 million. The estimated five year total cost of the plan is $20 million.

4.4.3 In oral evidence, the Companies' witness testified that ICI customers were opposed to financial incentives to encourage participation in the DSM programs, seeing these incentives as a form of cross-subsidy by one competitor of another.

4.5 INTERVENOR EVIDENCE

4.5.1 GEC filed a report entitled "Assessment of the Centra/Union Gas Fiscal 1997 DSM Plan" by Optimal Energy Inc. The authors of the report appeared as a witness panel on behalf of GEC. While conceding that the Companies' combined plan for DSM was an improvement over previous plans, GEC's witnesses found some of the programs to be poorly defined and insufficiently aggressive, particularly in the ICI sector. In their oral testimony, these witnesses expanded on their views of the shortcomings of these programs, especially in comparison with programs of other utilities, and recommended that, while the Board should approve the amounts budgeted for ICI DSM programs for fiscal 1997, it should not approve the overall ICI plan. They also recommended that the Board direct the Companies to complete the development of the ICI Plan, at the shareholder's expense, to propose an incentive mechanism to reward or penalize shareholders based on the success of the DSM programs in maximizing customer benefits, to establish a lost revenue adjustment mechanism ("LRAM") to remove any inherent disincentive toward sales reductions resulting from efficiency improvements, and to establish a deferral account mechanism for DSM expenditures. The recommended deferral account would be used to accrue the difference between actual DSM expenditures and forecast expenditures, as recommended by the Board in E.B.O. 169-III; and any over- or under- spending would be reviewed by the Board at the next rates case.

4.5.2 Under cross-examination the witnesses acknowledged limitations in the comparative data they had provided, and could not provide estimates of the cost involved in implementing their recommendations.

4.5.3 Pollution Probe filed a report by The Goodman Group, Ltd. evaluating the Companies' avoided costs estimates for use in screening DSM measures or programs. As a result of their findings, the authors recommended provision, by the Companies, of calculations of avoided costs for low, mid, and high gas price cost forecasts; gas price forecasts which are time-sensitive to expected market trends; and a more rigorous treatment of TCPL transportation costs. The authors also recommended a more complete explanation of the incorporation of avoided costs in the computer evaluation of DSM strategies, and of the impact of annual and seasonal load variability on DSM evaluations. To the extent that DSM had not been credited for all costs avoided, The Goodman Group, Ltd. recommended recalculation of the cost-effectiveness screening test. Finally, it was recommended that the Companies report, in the next rates case, on practical risk adjustment mechanisms and their expected impacts.

ADR Settlement Agreement

4.5.4 A separate ADR process was conducted among parties interested in DSM issues, resulting in an agreement on a number of aspects of the Companies' DSM proposals. The following parties participated in the ADR discussion: Kitchener, Schools, NOVA, ONA, Consumers' Gas, Board Staff, CAC, ECNG, Energy Probe, Enron, NRG, IGUA, OCAP and Pollution Probe.

4.5.5 In the ADR Settlement Agreement, the Companies committed to a general planning process for the improvement of DSM programs, and a residential sector planning process, both of which would be the subject of discussions in the DSM consultation meetings, as would their respective results. They also confirmed their intentions to obtain the necessary information for monitoring and evaluating the 1997 DSM programs, and that no DSM program would be implemented until a monitoring and evaluation plan for it was in place. Having regard to these commitments, no party opposed the Residential market portion of the DSM Plan (Programs 1, 2 and 3 above).

4.5.6 The Companies also agreed to a number of inclusions related to avoided cost measurement in the formulation of the next DSM plan, resulting in agreement by the parties that avoided costs used in the 1997 DSM Plan need not be examined further in the hearing.

4.5.7 No agreement was reached on the following:

a) *Review of 1995 and 1996 expenditures on DSM programs and planning process, review of results of 1995 and 1996 DSM programs including participants & volumes, and shareholder expenditures on development of 1997 DSM plan.*

b) *Institutional, Commercial and Industrial programs of the 1997 DSM Plan including proposed budget adjustments for 1997.*

c) *DSM Deferral Account (proposed by some intervenors).*

d) *Shareholder Incentive Proposals and/or Lost Revenue Adjustment Mechanisms.*

Positions of the Parties

In the following Section, the positions taken by parties on each of the above issues is set out.

a): *Review of Expenditures and Results of 1995 and 1996 DSM Programs and Allocation of Expenditures on Development of 1997 DSM Plan*

4.5.8 In argument-in-chief, the Companies outlined the benefits of the 1997 DSM Plan, noting that the 1997 DSM Plan has budgeted O&M costs for both Companies which represent approximately a 150% increase in spending over budgets approved by the Board in E.B.R.O. 486 and 489, and that forecast gas savings represent substantial increases over those proposed by the Companies in the earlier hearings. They argued that the 1997 DSM Plan is comprehensive and complete, and represents "an appropriate balance of aggressive measures, realistic expectations, and ratepayer impacts."

4.5.9 Board Staff noted the consistent pattern of over-spending of DSM O&M budgeted amounts and under-spending of DSM capital allowances for 1995, and the lack of information available from the Companies on 1996 DSM expenditures. Board Staff submitted that the Companies should be required to file complete financial records of expenditures and gas volumes saved on historic, actual and forecast bases in future cases.

4.5.10 Board Staff noted that in its E.B.R.O. 486 Decision, the Board ordered Union to redevelop its DSM program at shareholder expense. Board Staff accepted that the shareholder has contributed $1.016 million to the redevelopment, but submitted that the redevelopment of the 1997 DSM Plan is not complete. Board Staff therefore submitted that future costs associated with the completion of the 1997 DSM Plan should be reported separately in the next rate case, and charged to Union's shareholder.

4.5.11 CAC stated that in its view, the 1997 DSM Plan represents a good faith effort on the part of the Companies to address earlier Board criticisms of Union's DSM efforts, and that the details of the DSM program should be left to be developed by the Utilities and the consultative process, rather than being subject to detailed review by the Board.

4.5.12 CIPEC supported the Utilities' proposed industrial DSM programs, noting that a number of the programs have been successfully introduced in the Centra franchise area already. CIPEC submitted that if Westcoast moves energy management and DSM out of the regulated sphere, the total cost of developing the 1997 DSM programs should be borne by the shareholder, and not the ratepayers.

4.5.13 GEC submitted that, while Centra/Union have made "significant strides forward" in developing DSM programs, the 1997 DSM Plan is incomplete. More specifically, GEC submitted that there has been inadequate market research and analysis to determine which programs should be screened, and that not all cost effective measures which were screened were incorporated into the programs. In GEC's view, nothing is in place to capture the lost opportunities in large apartment and commercial buildings, such as incentives to replace failing equipment with more efficient equipment. They also criticized the Companies' strategies for obtaining participation in those programs which have been included in the 1997 DSM Plan. GEC submitted that the Board should find that "market characterization is needed to meet the requirements of a complete initial plan and it is thus appropriate to allocate the expense to shareholders". GEC criticized the Companies' screening processes, noting errors in the screening results, indicating, according to GEC, an incomplete and inadequate process.

4.5.14 GEC also submitted that the definition of "free riders" used by the Utilities is in error, and asked that the Board direct the Utilities to use the definition of free riders provided in the E.B.O. 169-III Report. Further, GEC submitted that significant alternatives have not been analyzed and documented to support the strategies chosen in the 1997 DSM Plan. In GEC's view, the Companies are sacrificing participation because of user pay concerns, and are not realizing the extent of cost effective savings which would be possible if the Companies made an appropriate balance between increased savings, net benefits and rate increases. In this respect, GEC contended that Union/Centra have not complied with E.B.O. 169-III guidelines for the development of their DSM programs.

4.5.15 GEC submitted that for the 1998 DSM plan, the Utilities should be directed to attempt to maximize achievable potential through an explicit and documented process of weighing different levels of rate impacts with increased net benefits, and that this work should be carried out at shareholder expense. GEC also submitted that the Utilities should, for the 1998 DSM plan, set the level of customer contributions which would be appropriate to balance the competing goals of user pay and high participation. In their view, documentation should be provided of an optimized portfolio, and of the considerations of various options to achieve this. Complete estimates of the program impacts should be presented in the filing for the first five years and for subsequent periods.

4.5.16 To the extent that the 1997 DSM Plan is deficient, GEC recommended that it be recast for the 1998 rates case, with the expenses of the redevelopment to be borne by the shareholder. Because of the uncertainties due to the inadequate plan developed for the 1997 rates case, and cost uncertainties due to variances in participation rates, GEC submitted that the 1997 budget should be included in rates as submitted, subject to a variance account.

4.5.17 HVAC submitted that the Utilities' general DSM objectives and general approach to program design appear to conform with the Board's E.B.O. 169-III Report. HVAC supported the broader involvement of the heating and cooling equipment industry in the fee-for-service component of the home and building retrofit programs associated with the 1997 DSM Plan.

4.5.18 Pollution Probe submitted that the DSM programs suggested by the Companies were not aggressive to the extent required by the Board's directives in the E.B.O. 169-III Report. Pollution Probe therefore submitted that the plan is not in compliance with the directives in the E.B.O. 169-III Report, and the E.B.R.O. 489 and E.B.R.O 486 Decisions. In Pollution Probe's view, "only modest energy costs savings" will result from the proposed DSM programs. Pollution Probe submitted that the Board should reduce the Companies' returns on equity as a result of their failure to develop aggressive DSM plans, and should take into account actual 1997 DSM savings and forecast 1998 DSM savings when setting returns on equity for 1998.

4.5.19 ONA was in substantial agreement with the positions of GEC and Pollution Probe with respect to improvements of the DSM Plan, and submitted that DSM plans "should be based on, and integrated with, [ONA's] articulated environmental principle". Accordingly, ONA requested that the Companies be directed to bring forward at the next rates case, a statement of principles and objectives reflecting the manner in which the proposed DSM plans will effect a commitment to environmental protection.

4.5.20 In reply, the Companies re-iterated their submission that the 1997 DSM Plan complies with earlier Board directives, and argued that detailed criticism of individual programs was inappropriate. They submitted that the 1997 DSM Plan is complete, acknowledging that while it is not perfect, it will be subject to further refinement as the Companies "learn by doing". They submitted that it would be "unnecessary and unfair to visit additional expense on Union's shareholder."

4.5.21 More specifically, the Companies submitted that:

! The basic components of a monitoring and evaluation plan have been established. In oral evidence, the Companies' witness agreed that no program would be implemented until complete monitoring and evaluation procedures were in place for that program;

! Achievable potential has been used in the design of the 1997 DSM Plan; a technical study on achievable potential being undertaken in cooperation with Consumers' Gas, is part of the work plan in the test year;

! While GEC criticized the 1997 DSM Plan as having missed important measures, no specific missing measures were either identified by the GEC witnesses, or suggested by GEC, during the consultative process. In the Companies' view, the measures included are sufficient;

! Screening errors that occurred, if any, were small; cost effectiveness was not affected;

! Although GEC criticized the 1997 DSM Plan's definition of free riders, the definition used was that set out by the Board in its E.B.O. 169-III Report. In any case, nothing turns on the definitional debate as far as the DSM programs or the overall Plan are concerned;

! GEC's submission that the 1997 DSM Plan does not contain alternative implementation strategies and delivery channels is incorrect. Many alternatives are included in each program; the market will determine which are most effective. No optimization analysis is necessary in this comprehensive approach;

! Sensitivity to rate impacts is both appropriate and in keeping with concerns expressed by the Board in both the E.B.O. 169 Report and this hearing. Impacts are occasioned by costs of the Plan, as well as through lost revenues. User pay principles are important in developing a DSM Plan; customers' rates should not be increased by programs from which they do not benefit; and

! The Companies are tracking information which will allow future reporting of the type suggested by Board Staff.

4.5.22 In response to Pollution Probe's arguments in favour of more aggressive DSM by the Companies, the Companies submitted that comparisons made by Pollution Probe were the results of incorrect analysis, comparisons having been based on figures which were not comparable. As to the argument that senior management must be motivated to improve DSM programs through reductions in the return on equity, the Companies point to the evidence of the Companies' witness, the Director, Environment and DSM, that he was under no "direct or indirect constraint against the aggressive pursuit of DSM targets."

b): ICI Programs

4.5.23 Board Staff submitted that the ICI programs, budgets and participation projections of the Utilities should be conditionally accepted by the Board, allowing the Companies the opportunity to prove their competence in this, the first year of the 1997 DSM Plan. The acceptance should be conditional on the Companies' implementation of appropriate monitoring and evaluation techniques as agreed to in the ADR Settlement Agreement. In making this submission, Board Staff noted the criticisms of the 1997 DSM Plan by the witness panel presented by GEC, but submitted that this panel's evidence was not convincing in this respect and should be disregarded by the Board.

4.5.24 CAESCO generally supported the 1997 DSM Plan filed by the Companies, and specifically supported the ICI program and its proposed use of ESCOs as part of the building retrofit program, and in the large industrial sector. CAESCO submitted that the Board should approve the 1997 DSM Plan, and include its budget in rates. CAESCO did not, however, support the use of substantial financial incentives in the ICI sector, arguing that such programs "tend to destabilize the energy savings retrofit market", and are unnecessary, given the growth of the energy services industry in recent years.

4.5.25 CAC took the view that, leaving aside the question of financial incentives, the Undertakings given by the Companies as part of the ADR Settlement Agreement adequately address the eight recommendations made by GEC's authors relating to the ICI portion of the 1997 DSM Plan. The two recommendations that GEC's experts suggested were not covered, are, in CAC's view, matters requiring analysis and most suitably addressed in the next rates case. With respect to the need for financial incentives, CAC noted that GEC's experts were not able to provide any estimate of the costs which would be borne by the ratepayers as a result of implementation of incentives, and that these incentives were, by the admission of GEC's own witnesses, premature. It submitted that the proposed ICI programs and budget should be approved, with the recommendation that the Companies address, where possible, the recommendations of GEC's witnesses in carrying out its undertakings relating to the further development of its non-residential programs.

4.5.26 CIPEC submitted that, if the Board does not approve the ICI program, the Board should direct the Utilities to reallocate all 1997 DSM costs to the residential rate classes.

4.5.27 GEC set out its view of the short-comings of the 1997 ICI DSM programs proposed by the Companies. GEC argued that significant reworking of the ICI programs must be done, with the consequent costs borne by the shareholder. They submitted that financial incentives should be offered in the industrial sector to ensure that market barriers to the uptake of potentially cost effective conservation measures are diminished. GEC noted that rate impacts from reduced revenues caused by reduced gas bills would be mitigated by the resulting broad-reaching bill reductions in the industrial sector from savings created through incentive programs. In short, GEC recommended that the Board direct the Companies to provide in the 1998 rates case, a more aggressive ICI DSM plan, and an analysis of conservation market potential, a forecast of significantly higher participation rates, and supporting evidence on rate impact trade-offs and plan optimization.

4.5.28 IGUA adopted and supported the submissions of CIPEC with respect to DSM issues.

4.5.29 With respect to the Industrial Process Improvements program, Pollution Probe submitted that the Board should encourage the Companies to raise their volume savings targets for this program in 1997. Noting that the Board in its E.B.R.O. 489 Decision directed Centra to "make further efforts to raise the minimum efficiency of its water heaters," and that Consumers' Gas has established a minimum efficiency standard for its commercial rental tank-type water heaters, Pollution Probe argued that the Board should direct the Companies to establish a similar standard.

4.5.30 The Companies replied that GEC's criticisms of its ICI programs were not supported by any factual evidence that would justify a more aggressive approach, specifically through financial incentives. They noted that the market transformation approach taken by the 1997 DSM Plan was agreed to by GEC's witnesses and argued that measure-specific information is not relevant to such an approach, as supported by the fact that Wisconsin Gas, cited by GEC as a model utility in respect of DSM, is moving away from product/measure specific rebates towards a model similar to that proposed by the Companies. The Companies also noted that their evidence that Centra/Union customers do not want financial incentives in any case, was uncontradicted.

4.5.31 With respect to GEC's argument that large commercial customers were ignored in the Building Equipment Replacement Program, the Companies pointed out that large volume customers are eligible under the Program if they use the residential-type equipment addressed by the Program. If they use more sophisticated equipment, their needs are addressed by the Building Retrofit Program. GEC's proposed use of financial incentives in the Industrial Process Improvement Program was, in the Companies' view, inappropriate, given the views of the customers and the necessity to recognize the user pay principle.

4.5.32 The Companies argued that GEC's assumptions giving rise to its criticism of low forecast participation rates were incorrect. In any case, they argued that the approach being taken by the Companies is a long-term one, which will, they contended, achieve high participation rates without incentives.

4.5.33 The Companies did not reply to Pollution Probe's argument relating to the establishment of a minimum efficiency standard for its commercial rental tank-type water heaters.

c): DSM Deferral Account

4.5.34 Board Staff noted that deferral accounts for the expenses related to DSM initiatives had been endorsed by the Board in E.B.O. 169-III and that a number of intervenors supported the creation of such an account in the current hearing. Board Staff submitted, however, that, given the extensive experience the Utilities now have with DSM initiatives, and the likelihood of accurate forecasting by the Utilities of the expenditures for the test year, no such account is either necessary or desirable. With respect to the argument by CIPEC that such an account should be established “in light of Westcoast’s proposal to move energy management out of the regulated sphere”, Board Staff submitted that discussion of this possibility is premature at this time.

4.5.35 CAESCO did not support the establishment of a deferral account for DSM at this time.

4.5.36 CAC supported the implementation of a deferral account mechanism for the Companies on the same basis as that established by Consumers’ Gas, with its disposition being determined principally on the basis of the prudence of the expenditures in light of the DSM program results and the Board's guidelines in the E.B.O. 169-III Report.

4.5.37 CIPEC submitted that the Board should direct the Companies to establish a DSM variance account to capture the actual costs of designing, developing and delivering the 1997 DSM programs. Should the decision to move these programs out of regulation be taken, the Board would then, in CIPEC’s view, have sufficient information to properly allocate these DSM costs between the shareholder and the ratepayers.

4.5.38 Arguing that there is “great uncertainty” whether the budget submitted by the Companies for DSM is appropriate, that “lack of a variance account acts as a disincentive to aggressive pursuit of DSM participation during the rate year and risks unfairness as between customers and shareholders", and that "no significant hearing time or expense is required to clear such an account", GEC submitted that there is a need for a variance account for DSM expenditures. It suggested a possible positive variance limit on the account, perhaps equivalent to 25% of the 1997 DSM budget.

4.5.39 Pollution Probe supported the establishment of a variance account for 1997 DSM expenditures.

4.5.40 The Companies did not agree that a variance account was needed. In the event of DSM activities being moved out of the regulated business, cost and transfer pricing would be dealt with at that time, as noted in the ADR Settlement Agreement. They submitted that tracking of DSM expenditures has improved, and in any case expenditures on a calendar, as opposed to fiscal, year basis is accurate and complete. There was therefore no need for a deferral account for the purpose of tracking expenditures. As for allowing "a more thorough review of the amount, adequacy and propriety of DSM spending", a deferral account was no more necessary for DSM expenditures than for any other. The Companies argued that a mechanism to provide an "open-ended increase in the 1997 DSM budget", would exacerbate the Board's understandable concern to contain rates.

d): LRAM and Shareholder Incentive

4.5.41 Board Staff submitted that there was no need for either an LRAM or a shareholder incentive at this time, as there was no proposed model before the Board, no evidence of the financial implications or impact on the Companies' risk assessment, and the Utilities opposed both measures.

4.5.42 CAESCO submitted that incentives for the Companies to conduct DSM programs should be considered in the context of performance-based regulation in general, and that, following discussion of possible incentive mechanisms by parties in the consultation process, the Utilities should report on the discussions at the next rates case, and propose incentive measures that are consistent with performance-based regulation.

4.5.43 CAC supported the suggestion that the Companies study, and report on, a possible LRAM and a shareholder incentive mechanism, and further suggested that the Companies be directed to consult with Consumers' Gas to coordinate these studies.

4.5.44 GEC supported a move towards effective incentive regulation of DSM and submitted that a study of such options should be undertaken by the Companies at this time, regardless of the Companies' overall direction. In GEC's view, an LRAM and a shareholder incentive, such as shared saving, should be two principal components of incentive regulation of DSM.

4.5.45 Pollution Probe submitted that the Companies should be directed to develop, in consultation with interested stakeholders, an LRAM for consideration in the next main rates case. Centra and Union should also, according to Pollution Probe, be directed to develop a shared savings incentive for the Board’s consideration in the next main rates case.

4.5.46 In the Companies’ view, the 1997 DSM Plan is sufficiently aggressive and complete, is being pursued diligently by management, and therefore does not require specific DSM performance regulation through either an LRAM or a shareholder incentive mechanism.

Board Findings

4.5.47 The Board has, in earlier cases, issued a number of suggestions and directives to each of the Companies relating to the development of DSM programs. To the extent that these related to residential programs, the parties agreed that the Companies’ commitments in the ADR settlement process obviated the need for an examination in this hearing of those programs, and the extent to which the earlier directives were met. The parties also agreed that the monitoring and evaluation plans and the Companies’ commitments in regard to them made it unnecessary to address those areas.

4.5.48 The Board had in E.B.R.O. 486 directed the development of a DSM plan in compliance with the guidelines contained in the E.B.O. 169-III Report. The Board finds that the 1997 DSM Plan put forward by the Companies, including the ICI programs, while not without need for further improvements, does represent a good faith effort to respond to the criticisms of the Board in earlier decisions and to directions given by the Board in the E.B.O. 169-III Report.

4.5.49 The Board notes the commitments the Companies have made as part of the ADR settlement process to continue consultation with stakeholders to improve the Plan, and to provide information to them on such matters as avoided costs. The Board expects that these consultations will result in an improved Plan. In particular, the Board expects the Companies, in fulfilling their commitments, to take into account the recommendations made by GEC's experts.

4.5.50 The Board also notes that, in their residential sector planning process, the Companies have committed to “investigate alternative strategies (including those that have been successful for other utilities)", and that a technical study on achievable potential being undertaken in cooperation with Consumers' Gas is part of the Companies' work plan. Consumers' Gas now has considerable experience in DSM planning and performance in the Southern Ontario context, and the Board encourages the Companies to benefit from their experience, and to aim for comparable results.

4.5.51 In its Decision in E.B.R.O. 489, the Board directed Centra ".. to make further efforts to raise the minimum efficiency of its water heaters, to increase the number of water heaters purchased that meet the ECP Guideline, and to prefile the results of these efforts as part of its DSM program planning in its main rates case." It appears from the evidence that the Companies have initiated an efficiency standard for residential rental water heaters, but that none is in place for commercial rentals. While the Companies' witnesses stated that it would be unreasonable to put such a standard in place, since commercial customers select their own units, the Board is of the view that it is within the Companies' power to make the necessary "financial arrangements" to turn a customer's purchase into a rental agreement only if the unit meets a specified minimum efficiency. No argument was made by the Companies in reply to Pollution Probe's submission that such a minimum efficiency standard should be implemented. The Board directs the Companies to implement such a standard through the arrangements it makes to turn purchases into rental agreements.

4.5.52 The Board accepts the Companies' agreement to file complete records of expenditures on DSM and volumes of gas saved.

4.5.53 The Board is not persuaded of the need for a deferral account to track DSM expenditures, or that a LRAM or shareholder incentive is needed at this time. As noted above, the Companies are committed to continued improvement of the 1997 DSM Plan and do not support the need for further incentives. As suggested by CAESCO, further discussion of possible future implementation of incentive measures should be consistent with the general move towards performance-based regulation.

4.5.54 The Board is concerned that the Companies appear to have made no attempt to optimize the DSM Plan. The Board is of the view that a reasonable approach to optimization of the plan, while limiting ratepayer impact, is to examine the rate impact of programs and their results, and favour those programs with the lowest rate impacts and best results. As noted elsewhere in this Decision, the Board is concerned with rate impacts in all aspects of the Companies' operations. DSM Planning is no exception. The Board directs the Companies to address the question of optimization, in particular, the optimum savings with the minimum ratepayer impact, in its next DSM Plan.

4.5.55 The Board notes CIPEC's submission concerning the possible removal of energy management and DSM programs from the Companies' regulated operations, and directs that, in that event, a detailed cost allocation in accordance to the guidelines agreed to for proposed separation of other programs, be undertaken to determine which costs should be borne by ratepayers and which by the shareholder.

4.5.56 The Board notes that a directive to Centra in its E.B.R.O 489 Decision had required the separation of DSM program components from the general marketing activities. In their evidence, the Companies have noted that DSM evidence is provided separately from marketing evidence, and that a separate DSM department has been created. They also note, however, that "there is a very close working relationship with marketing as the marketing department remains responsible for the delivery and implementation of DSM programs". The Board has expressed its concerns relating to the marketing of DSM-related merchandise in its discussion of the Union Energy Catalogue in Chapter 3 of this Decision.

4.5.57 The Board finds that the proposed 1997 costs of the DSM Plan totalling $3.670 million, including market support, research and overhead expenses of $1.3 million, are appropriate to be included in the Utilities' costs of service for the test year. The allocation of these costs to Union and Centra is addressed in Chapter 9 of this Decision.

5. WESTCOAST CORPORATE CENTRE CHARGES

5.1 INTRODUCTION AND BACKGROUND

The Undertaking Applications

5.1.1 On February 16, 1996 Union and Centra applied to the Board pursuant to their respective Undertakings for approval of the payment of charges to Westcoast ("Westcoast Corporate Centre Charges," "Corporate Centre Charges") for services provided by Westcoast's Corporate Centre in 1996. The cost of these services was budgeted as $3.9 million for Union and $1.3 million for Centra. As noted in Chapter 1 the Board assigned Board File Nos. E.B.R.L.G. 34-19 to the Centra Application and E.B.O. 177-09 to the Union Application.

5.1.2 Upon receipt of the Undertaking Applications the Board determined that it required further information on the proposed charges and that, since the proposed charges represented a major change, interested parties should have an opportunity to review and comment on them. Therefore, the Board decided that it would review the Undertaking Applications in conjunction with the hearing of the E.B.R.O. 493/494 main rates cases.

1997 Rate Applications

5.1.3 As part of the 1997 Rate Applications the Companies sought Board approval of the proposed 1997 Corporate Centre Charges as a repetitive affiliate transaction for inclusion in the cost of service of each Company for the test year.

5.1.4 The proposed 1997 charges were also $5.2 million, allocated as in 1996, $3.9 million and $1.3 million to Union and Centra respectively.

5.1.5 In the E.B.R.O. 486 and E.B.R.O. 489 Decisions the Board had approved for inclusion in the cost of service Westcoast charges in the following amounts: $360,000 to Union for specific financial and legal services to be provided by Westcoast in fiscal 1996 (year ending March 31, 1996); $323,000 to Centra for specific Direct Services, Treasury, Controller and Executive services, provided by Westcoast in fiscal 1995.

Genesis of Westcoast Corporate Centre Charges

5.1.6 The Westcoast Corporate Centre was established in January 1995 in response to initiatives by the Westcoast Senior Officers Committee to:

- *provide shared services to all of the Westcoast operating companies where it is efficient and effective to do so;*
- *establish and coordinate broad corporate goals and business strategies which would include building on the synergies of the operating companies and, where appropriate, having the best practices of one company adopted by another; and*
- *ensure sound governance, particularly as it relates to compliance with legal and regulatory requirements.*

5.1.7 As constituted in 1996 the Westcoast Corporate Centre was based in its own offices in Vancouver with a staff of 73, including 9 Executives, and a 1996 operating budget of $22.7 million. It is overseen by the Senior Officers Committee and comprises the following groups:

> Information Systems and Technology ("IS&T"), Human Resources (HR), Taxation and Audit, Risk Management, Planning and Development, Treasury, Corporate Controller, Investor Relations, Communications, Legal and Executive.

Prior Regulatory Decisions - Westcoast Corporate Centre Charges

5.1.8 In support of the Undertaking Applications the Utilities filed prior regulatory Decisions on the Westcoast Corporate Centre Charges.

5.1.9 In 1992 the National Energy Board ("the NEB") in its RH-1-92 Decision ordered an independent study of the allocation of costs of services between Westcoast's utility and non-utility operations. Arthur Andersen was retained to advise on cost allocation methodology. In its first report Andersen recommended a *cost driver* methodology.

5.1.10 In May 1995, prior to the NEB's review of Westcoast's cost driver allocation methodology, and without commenting on the cost driver methodology, the Manitoba Public Utilities Board ("PUB") approved an increase in Westcoast Corporate charges to Centra Gas Manitoba Inc. from $300,000 to $440,000 as part of its approval of 1995 O&M costs.

5.1.11 In its June 1995 RH-5-94 Decision the NEB gave a conditional approval to Westcoast's allocation of costs among its various operating entities based on cost drivers. The NEB found "Westcoast's qualitative description of the cost allocation methodology used for 1995 to be reasonable." However, the NEB agreed with an intervenor's position that intervenors require quantitative analysis in order to be able to comment on the reasonableness of the allocated costs. The NEB also noted that Westcoast had used the cost drivers in addition to time sheets.

5.1.12 The NEB approved Corporate Centre Charges to the Westcoast Pipeline Division for its 1995 test year in an amount of $4.359 million. In addition the Pipeline Division's cost of service would be reduced by the recovery of costs from the Corporate Centre for accounting services which the Pipeline Division provided to the Corporate Centre. The establishment of the Corporate Centre also reduced the services which the Pipeline Division had previously been providing to other affiliates. The net result was a reduction in affiliate-related O&M costs.

5.1.13 In E.B.R.O. 486 Union filed an Arthur Andersen report recommending a cost driver approach for allocating costs to its non-regulated activities. The Board stated in its Decision with Reasons dated July 19, 1995, that:

The Board is persuaded by the evidence that the cost driver methodology for non-utility cost allocation offers significant reductions in administrative effort and cost as well as being forward looking. (para. 4.9.14);

5.1.14 The Board in approving the use of a cost driver approach for non-utility eliminations, did not consider the concurrent use of timesheet data to be a cost-effective requirement.

5.1.15 In E.B.R.O. 486 with regard to Westcoast Corporate Centre Charges of $360,000 for specific financial and legal services, the Board directed Union:

to provide more substantiation for those charges in its next main rates case, specifically regarding the nature of the services provided and the basis for the charges. (para. 4.9.17).

5.1.16 In January 1996, the Alberta Energy and Utilities Board ("EUB") approved an increase in Westcoast Corporate Centre Charges to be paid by Centra Gas Alberta Inc. from $430,771 in 1994 to $461,106 in 1995. The Board noted that "investor confidence in Westcoast is essential to enable it to attract funds required to provide equity financing to Centra and to minimize Centra's debt financing costs." Therefore the Alberta EUB recognized that there was a need for Centra to contribute to costs required to maintain investor confidence and approved the costs allocated to Centra Gas Alberta Inc. for communications expense.

5.1.17 In May 1996, the British Columbia Utilities Commission reviewed Westcoast Corporate Centre charges proposed to be allocated to Pacific Northern Gas ("PNG") for 1996. The Commission allowed only an inflationary increase and required that "... PNG as a minimum provide a more rigorous analysis of the Westcoast allocation in future revenue requirements applications."

5.2 REQUEST FOR APPROVAL OF 1996 AND 1997 WESTCOAST CORPORATE CENTRE CHARGES

5.2.1 Westcoast Corporate Centre costs in 1997 are budgeted at $21.014 million. Of this amount $12.621 million has been allocated by Westcoast to regulated subsidiaries and the balance to the shareholder and non-regulated affiliates.

5.2.2 The Companies proposed an increase in total Westcoast charges to Union and Centra from $683,000 approved by the Board for 1995/96, to total Westcoast Corporate Centre Charges of $5.2 million in 1997. The Companies filed the following summary of the proposed 1996 and 1997 Corporate Centre Charges for which Board approval was sought in their Undertaking Applications and in their 1997 Rates Applications:

Table 5.1: Proposed Allocation of Westcoast Corporate Centre Charges to Union and Centra

Proposed Allocation of Westcoast Corporate Centre Charges to Union and Centra ($000's)						
	Union			**Centra**		
Service/Charge	**1995 Board Approved**	**1996 Proposed**	**1997 Proposed**	**1995 Board Approved**	**1996 Proposed**	**1997 Proposed**
DIRECT SERVICES						
IS Technology		292.0	265.3	20.3	91.0	82.7
Human Resources		199.0	151.3	3.9	118.0	89.7
Communications		360.0	354.0	7.2	115.0	113.0
Taxation and Audit		186.0	165.8	73.0	62.0	55.2
Risk Management		35.0	36.0		34.0	35.0
Planning & Development		209.0	170.7		69.0	56.3
Subtotal	**0.0**	**1,281.0**	**1,143.1**	**104.4**	**489.0**	**431.9**
ACCESS TO CAPITAL						
Treasury		505.0	456.0	135.9	186.0	168.0
Corporate Controller		286.0	256.7	33.4	95.0	85.3
Other						
-Investor Relations		225.0	276.7		75.0	92.3
-Trustee Fees		274.0	203.4		91.0	67.6
-AGM/Annual Report		128.0	263.5		43.0	88.5
Subtotal	**360.0**	**1,418.0**	**1,456.3**	**169.3**	**490.0**	**501.7**
GOVERNANCE						
Executive		797.0	831.2	42.1	183.0	190.8
Legal		251.0	229.3	7.2	85.0	77.7
Other:						
-Legal & Consulting Fees		168.0	134.2		56.0	44.8
-Directors Expenses		122.0	104.8		41.0	35.2
-Audit Fees		17.0	16.3		6.0	5.7
KPMG Adjustment		(154.0)			(52.0)	
Subtotal	**0.0**	**1,201.0**	**1,315.8**	**49.3**	**319.0**	**354.2**

5.3 CONSULTANTS' STUDIES - COST DRIVER APPROACH

5.3.1 In support of their Applications, the Companies and Westcoast filed a number of Studies and Reports which they had initiated:

- Arthur Andersen; November 1995; Westcoast Energy Inc. Corporate Centre: Review of Cost Allocation Methodology;

- KPMG Management Consulting ("KPMG"); December 1995. Union Gas and Centra Gas Committee of Independent Directors: Review of Fees Charged by Westcoast Energy Inc.'s Corporate Centre;

- Ernst and Young: June 1996; Union Gas and Centra Gas: Westcoast Energy Inc. Corporate Centre Value Analysis 1997 Budget - Final Report;

- Arthur Andersen; July 1996. Working Papers Supporting the 1997 Cost Driver Allocation of Corporate Centre Charges;

- Ernst & Young; September 1995. Westcoast Energy Inc. Corporate Centre Value Analysis-Final Report.

5.3.2 The experts retained by the Companies and Westcoast described the development of the cost driver approach for the allocation of Corporate Centre costs to Westcoast's regulated and non-regulated businesses. They noted that the cost drivers used for the current allocation were consistent with the somewhat more detailed cost drivers approved by the Board for Union's non-utility cost eliminations in E.B.R.O. 486.

5.3.3 The principal cost drivers used to assign the proposed Westcoast Corporate Centre Charges for 1996 and 1997 were:

- Rate Base/Fixed Assets (investment level);
- Head Count (business unit as a percentage of total head count);
- Executive Head Count (excluding corporate centre executive);
- IS&T Expenses;
- Number of Work Stations; and

- Financing and Cash Management:
  - Number of Financings
  - Level of Credit Facilities.

5.3.4 In addition direct allocation based on time sheets was used as appropriate.

5.3.5 The distribution of head count, rate base/fixed assets and revenue among the Westcoast group is shown in Table 5.2.

Table 5.2: Key Cost Drivers, Westcoast Companies (1996)

Distribution of Key Cost Drivers- Westcoast Companies (1996)				
Business Unit (R indicates regulated)	**Employees (head count)**	**Executive (head count)**	**Rate Base/ Fixed Assets ($ millions)**	**Revenues ($ millions)**
Westcoast Pipeline (R)	1,185	20	2.172	509
Union Gas (R)	2,615	44	2.103	1.246
Centra Gas Ontario (R)	822	16	735	509
Centra Gas Manitoba (R)	647	8	273	243
Centra Gas Alberta (R)	147	1	121	48
Centra Gas B.C. (R)	265	7	455	67
Pacific Northern Gas (R)	55	4	64	61
St Clair Pipeline (R)	12	3	101	N/A (1)
Subtotal Regulated Affiliates	**5,748**	**103**	**6.024**	**2.683**
Westcoast Power	72	7	223	N/A
SPD	6	1	7	N/A
Westcoast Gas Services	102	5	58	N/A
NGX	17	1	4	N/A
BCIP	2	0	0	N/A
Corporate	80	36	0	N/A
Subtotal Non-regulated Affiliates	**279**	**50**	**292**	**N/A**
WESTCOAST TOTALS	**6,027**	**153**	**6.316**	
(1) N/A - Not Available				

5.3.6 Although none of the other consultants' studies disagreed with the cost drivers reviewed and recommended by Arthur Andersen, KPMG in its Report disagreed with the specific application of certain cost drivers for some Corporate Centre Charges, in particular the use of Rate Base as a default. KPMG recommended the use of Executive Head Count for information technology, communications and planning costs. This change, and other adjustments recommended by KPMG reduced the proposed 1996 Corporate Centre Charges allocated to Union and Centra by Westcoast by $154,000 and $52,000 respectively. The KPMG Report was not updated for 1997.

5.3.7 The Companies' experts also reviewed the value that Union and Centra received from the Corporate Centre services. They concluded that the value was based on four tangible benefits:

- Replacement of utility resources;
- Synergistic or linkage services;
- Revenue enhancement or utility cost recovery; and
- Stand-alone value services.

The Companies' experts also concluded that intangible benefits were also received by Union and Centra.

5.3.8 KPMG concluded in its December 1995 Report that the tangible value of the benefits received by Union and Centra in 1996, would be $4.3 million compared to costs of $5.2 million. KPMG also concluded that the intangible benefits exceeded the $890,000 shortfall in tangible benefits.

5.3.9 Ernst and Young concluded in its June 1996 Report to Union and Centra management, that the Corporate Centre services were essential and that the quantifiable value of the benefits received by Union and Centra in 1997 would be $6.5 million compared to proposed costs of $5.4 million. Ernst and Young also concluded that the intangible benefits were significant.

5.3.10 The Companies' and Westcoast's witnesses stated that, historically, there had been underpricing of the services provided by the Westcoast Pipeline Division to other divisions and Westcoast affiliates and that this cross- subsidization was estimated at $2 million annually and therefore the corporate shared services costs needed to be allocated more appropriately. In late 1994 Union and Centra Executives became aware of the Westcoast corporate cost allocation study and the finding that there was "underpricing" of the services that the Companies had been receiving from Westcoast by about $4 million.

5.3.11 Because of the proposed significant increase in Westcoast Corporate Centre Charges to Union and Centra commencing in 1996, the Companies' management undertook to work with Westcoast to better understand the nature of the underpricing and the changes occurring as a result of the establishment of the Westcoast Corporate Centre.

5.3.12 The Companies focussed on elimination of duplication and overlap of services to be provided by the Corporate Centre and on the affiliate transactions involved, in order to ensure that the Companies would receive value for money. In addition, given the quantum of the proposed charges, the Companies recognized that there would be considerable scrutiny in the next regulatory proceeding and, accordingly, commissioned the KPMG Report referred to earlier. Having reviewed the KPMG Report, the Companies' Executive and the Committee of Independent Directors both concluded that the 1996 Westcoast Corporate Centre Charges were appropriate.

5.4 POSITIONS OF THE PARTIES

5.4.1 The Companies argued that the Corporate Centre approach was not unique to Westcoast and was gaining currency as an efficient means of providing consolidated services, particularly in organizations with some diversity. The cost driver methodology employed by Westcoast had been accepted by the NEB for allocation of Corporate Centre Charges to the Westcoast Pipeline Division, and other regulatory bodies had reviewed and accepted the methodology and the resulting charges.

5.4.2 Although acknowledging an element of judgement in the selection and application of the cost drivers, the Companies argued that their independent review had found that only $200,000 should be eliminated from the proposed 1996 charges, indicating that any differences in opinion among the experts were not substantial.

5.4.3 The Companies were also satisfied that, based on a thorough examination using a conservative approach, which included discounting the benefits in several cases, the value of the benefits received in both 1996 and 1997 were in excess of the proposed Corporate Centre Charges for the services to be provided.

5.4.4 The Companies argued that the Companies' claimed 1997 combined O&M budget of $294.6 million 1997 which contained the Westcoast Corporate Centre Charges had only increased by 3.4% over the Board-approved level of $284 million in 1995. This level of increase compared favourably with the rate of inflation and the increase in other utilities' O&M costs, thus demonstrating, in the Companies' view, that the 1996 and 1997 Westcoast Corporate Centre Charges are not a layer over an otherwise reasonable O&M budget, but in fact an intrinsic part of a very reasonable, conservative and prudent O&M budget.

5.4.5 Board Staff made submissions on each of the thirteen functional areas encompassed by the proposed Westcoast Corporate Centre Charges:

Information Systems and Technology - Board Staff noted that the benefits claimed related to volume purchase discounts and integrated planning and that Ernst and Young had estimated that $505,000 in benefits might be realized by the Companies. Board Staff submitted that there is no evidence that the charges arise from deficiencies in the Companies' IT department, or that they provide benefits to the ratepayer, since the function of the Corporate IS&T Group is to coordinate information systems across the Westcoast group of companies. Board Staff submitted that the claimed Microsoft software volume purchase discount benefit was suspect, because without the Companies the discount to other Westcoast subsidiaries would be much smaller. Consequently, in Board Staff's view, there should be a payment to the Companies for these substantial discounts. Board Staff submitted that in its view, the net benefit in IT skills development also flows <u>to</u> the Corporate Centre and other Westcoast companies from the Companies' IT department, which has a budget of over $40 million and a staff of 171. The real net benefit to the Companies from the Corporate Centre in Board Staff's submission, is nil.

Human Resources - Board Staff noted that Ernst and Young had quantified the replacement benefit of the Corporate Centre HR department activities as two FTE roles. Board Staff submitted that labour relations are diversified across the Westcoast operating regions and therefore the claimed benefits to the Companies are unlikely to be realized. Board Staff also noted that under the Companies' Shared Services initiative, $700,000 in HR department savings were to be realized and it submitted that the Corporate Centre Charges are a partial claw back of that amount. The real net benefit to the Companies' ratepayers, in Board Staff's submission, is nil.

Corporate Communications - Board Staff noted that these Corporate Centre Charges were proposed to be allocated to the Companies' Finance, Government and Media Relations and HR functions, and that the Companies had stated that the benefits are in the areas of investor relations, and governance activities. Board Staff submitted that the primary purpose of Corporate Communications is to ensure that Westcoast maintains an appropriate profile in the market place and disputed the Companies' claim that this profile trickles down to the Companies' benefit. Board Staff submitted that Westcoast Executives had confused the interests of Westcoast, the sole shareholder, and those of the Companies. Board Staff submitted that Westcoast's Corporate Communication costs should, as a matter of principle, be borne by the shareholder and they are, in any case, often duplicative of the Companies' own communications, such as newsletters and annual reports. In Board Staff's submission none of the activities of the Corporate Centre Communications Group provide benefits to the Companies' ratepayers.

Audit and Taxation - Board Staff submitted that there is no convincing evidence that conclusively demonstrates this Corporate Centre Group provides services that are not already provided for within the Companies. The role of the Corporate Centre Group is coordination and reporting throughout the Westcoast Group, and no charges to the Companies for the audit and taxation functions should be approved.

Risk Management - Board Staff noted this Corporate Centre function provides high level insurance coverage as well as premium negotiations and placements and that Union is currently examining whether it can provide some, or all, of these services to the Westcoast Group. Board Staff submitted that the evidence was that there had been direct reallocation of staff at Union and Centra, but no overall reduction in roles, as a result of the Company's risk management function moving to the Corporate Centre. Board Staff submitted that until a study supports the replacement or revenue enhancement benefit of the services, no amounts should be allowed for this service.

Planning and Development - Board Staff noted that the role of this Corporate Centre Group is to help develop proposals for business development from the Westcoast subsidiaries, including the LDCs. Board Staff submitted that the only benefit was in sharing research services, which cost $120,000 a year. Board Staff submitted that $84,000 of this cost might reasonably be charged to Ontario ratepayers.

Treasury - Board Staff submitted that these services represent a continuation of past affiliate Westcoast charges and the proposed charge of $624,000 to Union and Centra is appropriately incurred for the benefit of ratepayers.

Investor Relations - Board Staff noted Westcoast's statement that this "group served the function of keeping in touch with the financial community", and the Companies assertion that they would otherwise require their own manager of investor relations to raise money for the Companies. Board Staff noted that Ernst and Young were unable to account for $69,000 of the perceived benefit of $369,000. Board Staff submitted that the evidence does not support the payment of any costs related to investor relations. Board Staff submitted that the investors are investors in Westcoast and that on the stand-alone regulatory principle, the allowed return on the shareholder's common equity provides Westcoast with full compensation for all attendant risks of providing equity capital.

Board Staff submitted that the costs of issuing debt are paid either as part of the calculation of the costs of new issues, or as part of the embedded costs of current debt issues.

Legal Department - Board Staff noted that the Companies claimed that services provided by the Corporate Legal Group have replaced one Union/Centra Counsel and the services to be provided include additional corporate governance, and the sourcing of capital via securities filings and prospectuses. The Companies' evidence was that they produce their own securities reports, but that Westcoast has more extensive requirements. Board Staff noted that Westcoast's experts had stated that the $196,000 in claimed benefits do not match the cost in the test year and will take time to realize. Board Staff submitted that the Board should not approve any of the proposed Legal Department costs, since almost one half of the charges are unsubstantiated, the allocation of an FTE role reduction is a result of the Companies own Shared Services initiative, and any small remaining costs are a result of Westcoast's more extensive securities filing requirements.

Controller's Department - Board Staff noted the Companies' evidence that this Corporate Centre Group deals with acquisition of capital in support of the Treasury Group and provides expertise related to accounting policy. The Companies' own Controller's Department utilizes the Corporate Centre's accounting research. Board Staff noted that Ernst and Young could only identify $200,000 in benefits compared to the proposed charge of $342,000. Board Staff submitted that these costs are not appropriate to charge to Ontario ratepayers, since the evidence does not provide an understanding of the tasks formerly undertaken by Westcoast, relative to the tasks undertaken by the new Corporate Centre. The Companies' evidence is that two FTE positions are supporting the Treasury department which had previously done the work of bond rating presentations and other reporting functions.

Executive Group, Corporate Governance, Directors' Expenses - Board Staff noted that the Companies' proposed 1997 senior management budget is $8.3 million, including the proposed Corporate Centre Charges. Board Staff noted that as a result of the 1995 Shared Services initiative, the number of executives within the Company was reduced from 17 to 11. The Companies' evidence was that the Corporate Centre provided a safety net and that the main function of the Corporate Group was strategy development and execution including activities on behalf of the Companies. The claimed benefits of $1.4 million were based on 10% of the Companies' Shared Services annualized savings. Board Staff submitted with regard to Directors' Expenses that these reflect work done on behalf of the Companies by Westcoast directors. Additional governance activities relate to legal and consulting services, Westcoast's Annual General Meeting ("AGM"), the annual report, and trustee and agent transfer fees.

Board Staff submitted that the costs of these Corporate Centre groups are clearly excessive and redundant and are costs incurred by the shareholder in the management of its assets for which the shareholder has been appropriately compensated in the return on its common equity. Board Staff agreed with the arguments of CAC and OCAP that the estimate of Executive Group benefits are not based on any reasonable estimation of potential savings and the Corporate Centre did not exist at the time the Shared Services decision was made. In Board Staff's submission the Executive Group charges are an attempt to claw back some of the Shared Services benefits for the shareholder.

Board Staff also submitted that KPMG, in assigning part of the benefit for the Shared Services initiative to the shareholder, had misunderstood the nature of regulated rates of return. In Board Staff's view, under the current regime, utilities and management are compensated for productivity improvement costs while the shareholder captures any unforecast increase in productivity.

With regard to Westcoast Directors' Expenses, Board Staff submitted that based on the stand-alone standard, it is not appropriate for the ratepayers to pay for Westcoast Directors' Expenses. Board Staff argued that ratepayers are not obligated to pay twice for the privilege of being managed by Westcoast - once in the cost of equity capital and again in operating costs.

5.4.6 In summary, Board Staff argued that the Board should approve for both Companies $624,000 of Treasury services and $84,000 of Corporate Planning and Development costs for a total of $708,000.

5.4.7 Board Staff also commented on the studies filed by Westcoast and the Companies in support of their Applications to include the Corporate Centre Charges in the 1997 cost of service. Board Staff submitted that the Companies' decision not to call a witness from KPMG, which authored the only study commissioned by the Companies' Independent Directors, and which concluded that there are at least $890,000 in unquantifiable benefits, does not lend itself to proving the Applicants' case.

5.4.8 Board Staff submitted that having justified the existence of the Corporate Centre in the first place, Ernst and Young were not in a good position to give a truly unbiased assessment of the value the Centre provides to Union and Centra.

5.4.9 Board Staff submitted that there is a very heavy onus on the Applicants to prove that the identified savings are achievable on an annual basis. In addition, intercorporate transfers in excess of $1 million that are not easily compared to available market services, should not be approved on the basis of internally sourced studies. Board Staff suggested that, should the Board agree with the positions of a number of parties and approve significantly less than the requested amounts, the Board could appoint an independent outside party to review the necessity for Corporate Centre Charges.

5.4.10 CAC argued that the Companies have not adequately justified the full $5.2 million in Corporate Centre Charges. Although CAC recognized that the Corporate Centre can provide some valuable services it was not convinced that all of those services are required and that the value of those services exceeds the proposed $5.2 million charge.

5.4.11 CAC submitted that the appropriate test as to whether the allocated costs are reasonable, is whether or not it can be substantiated that the Utilities are receiving services they truly require at a reasonable cost.

5.4.12 CAC pointed out that the Westcoast Corporate Centre budget, which was the starting point of the allocation process, had not been independently scrutinized, and advised the Board to be mindful of this when it is considering the appropriateness of the allocated costs to the Utilities. Another difficulty was the assumption that the Companies should bear a portion of the sole shareholder's costs, even if these were part of the cost of doing business for Westcoast, e.g. the Annual General Meeting. A further difficulty was the fact that the proposed Corporate Centre allocation did not comprehensively account for the fact that benefits from the Utilities, the two largest entities within the Westcoast group, flow to other companies.

5.4.13 CAC, having examined the benefit/cost of the services provided by the Corporate Centre, concluded that the total of costs to be borne by the Utilities should be $1.425 million in 1997, with no allocation justified for HR, Communications, Corporate Controller, Executive Group, Legal and other charges.

5.4.14 CAC further submitted that these approved charges should only be viewed as one time costs which Centra and Union must continue to justify as appropriate in future years, and that a more detailed examination of the Corporate Centre budget was necessary, rather than, as in this case, the Companies' consultants accepting previously accepted charges as a given.

5.4.15 IGUA submitted that the Corporate Centre Charges which the Companies are seeking to recover in the 1997 test year ought to be reduced because some of the proposed activities of the Corporate Centre representatives were clearly related to "minding the investment" of the parent, which the Board had previously found in the case of Norcen (E.B.R.O. 314-1-13) to result in costs not chargeable to the regulated utility. The rate of return that Union and Centra are allowed to earn is the benefit that Westcoast receives for minding its investment in the Companies.

5.4.16 IGUA submitted that when assessing the level of the Westcoast Corporate Centre Charges to be allowed for recovery in rates, the Board should take into account the fact that the results of the application of a cost driver methodology can be significantly influenced by the selection of the cost driver for a particular centre of cost incurrence. The cost drivers which have been used to derive the allocation of the Corporate Centre Charges to the Companies were, in large part, asset or head count related and there was not one instance of a cost which was allocated equally to all members of the Westcoast family.

5.4.17 IGUA also submitted that if the same cost driver approach were used to fully allocate costs to ancillary activities of the Companies, there is a strong likelihood that the returns being earned by such activities would fall below the overall return allowed to the Companies, with the result that revenue would be imputed to ancillary activities when deriving rates to be charged for provision of regulated monopoly services. This would reduce the extent of the cross subsidy and produce lower rates for the regulated monopoly services.

5.4.18 Based on the precedent established in the E.B.R.O. 314-1-13 Norcen Decision in which a $1.1 million management fee was disallowed based on the "minding the investment" principle, IGUA submitted that the Corporate Centre Charges recoverable in the 1997 test year ought to be reduced by at least $1 million.

5.4.19 OCAP submitted that there were four principal concerns with regard to Corporate Centre Charges:

- benefits must be quantified;
- costs must be reasonable and justified by the evidence;
- normal shareholder costs should not be charged directly to ratepayers; and
- activities should provide tangible benefits to Ontario ratepayers.

5.4.20 OCAP submitted that based on its analysis of quantified benefits, $709,000 of costs were wholly unsupported because the costs exceed the claimed benefits and, as a starting point, should be disallowed from the cost of service. OCAP expressed its concern that by shifting costs into the Corporate Centre, Union and Centra were removing those costs from one layer of regulatory scrutiny. Given these conditions the Companies must make an especially solid case for approval of Corporate Centre Charges. OCAP also submitted that Westcoast shareholders do not need to be compensated for Westcoast's costs through Ontario gas distribution rates. Every company incurs investor costs which are compensated by the return on equity, which, for regulated entities, is set to be comparable to similar unregulated companies. OCAP expressed its alarm at the amount of costs that Westcoast is proposing to allocate to Ontario ratepayers, which costs, in its view, have no direct bearing on the ability of Union and Centra to manage their systems.

5.4.21 Having examined the proposed Corporate Centre Charges in more detail, OCAP recommended that the following costs be totally disallowed: $348,000 of IS&T costs, $241,000 of HR costs, $467,000 of Communications costs, $369,000 of Investor

Relations costs, $227,000 of Corporate Development and Planning costs, $1,022,000 of Westcoast Executive costs, $140,000 in Westcoast Directors' Expenses and $307,000 of Corporate Legal costs. OCAP also recommended partial disallowance of Treasury costs to 1995 levels representing a $135,000 reduction from the requested $624,000, a partial reduction of $142,000 out of $342,000 for the Corporate Controller's expenses, and a reduction of $421,000 in Other Charges.

5.4.22 Based on the above, OCAP argued that the Board should find $3.819 million of Corporate Centre Charges unjustified and therefore allow only $1.389 million in the 1997 test year.

5.4.23 The Companies submitted an extensive reply argument in response to the intervenors' arguments. The Companies noted that the intervenors did not disagree in principle with the Charges, but only with the degree to which the 1997 Charges should be approved for ratemaking purposes and that the opposing intervenors were far from unanimous in their respective positions.

5.4.24 The Companies reiterated that, given the nature of the affiliate transaction and the scale of the increase, they realized that the request would attract close scrutiny and for this reason senior management went to considerable lengths to ensure a close internal examination.

5.4.25 The Companies noted that inter-affiliate transactions are a fact of life in Ontario and that the Board had recently approved a payment by Consumers' Gas to its parent in an amount of $1.438 million for treasury services and one of $2.2 million for insurance services to a subsidiary of its parent. In the Companies' view, these approvals recognize that it will frequently be in the interests of ratepayers to obtain cost effective services through affiliate transactions, and that the Board will scrutinize the charges in relation to the value received.

5.4.26 The Companies submitted that certain of the intervenors' submissions did not comply with the rules of evidence, fair play, natural justice and ordinary onus which apply to rate proceedings. If Board Staff's position is accepted, then the Companies' 1997 O&M budget would be only 1.8% more than the Board-approved 1995 level.

5.4.27 The Companies submitted that Westcoast is not compensated in the Companies' rate of return on common equity for the costs associated with raising $168 million in debt for Union and Centra in 1997. Due to consolidation at the Westcoast level, the cost is lower than it otherwise would be on a stand alone basis. These principles have been accepted by several regulatory Boards, including the NEB, the Manitoba PUB, and the Alberta EUB.

5.4.28 The Companies disagreed with intervenors who submitted that the nature of the proposed charges meant there would be less opportunity to test the underlying budget and that shared services were inherently prone to be duplicative and add extra costs. They also disagreed that the two way flow of benefits was not appropriately recognized in the proposed allocation of the Corporate Centre Charges.

5.4.29 The Companies reviewed their consultants' conclusions about the non-quantifiable benefits which, in their view, when added to the quantified benefits, clearly justified the Westcoast Corporate Centre Charges. In the Companies' submission they have met the onus of establishing that the affiliate transaction produces value for the ratepayers in excess of the Corporate Centre Charges.

5.4.30 The Companies provided a rebuttal of the intervenors' submissions regarding: the impact of the selection of cost drivers; the independence of the consultants retained by both Westcoast and the Companies; and the fact that the Companies did not call a witness from KPMG.

5.4.31 The Companies addressed the detailed submissions of the intervenors and argued that in each case the Corporate Centre Charges were justifiable and supported by their experts' analysis of the benefits to ratepayers.

5.4.32 In their summary submissions the Companies argued that:

- the Corporate Centre services are necessary, are provided on a cost effective basis, yield benefits in excess of the charges and have no added margin for the shareholder;

- in the event the service charges are disallowed and the Utilities not given the means to pay for the services in 1997, the Utilities will be faced with the prospect of either eliminating services with detrimental impacts on service or asking the shareholder to continue to cross-subsidize the provision of services in Ontario;

- in the longer term, if the approach recommended by intervenors is adopted, the Utilities will simply reduce service levels or replace the services internally, thereby foregoing the efficiencies associated with the coordination of shared services at the Corporate Centre level;

- the necessary impact of the substantial reduction in Corporate Centre Charges advocated by certain parties will result in a detriment to ratepayers, or unfairness to the shareholder, or both; and

- the 1996 Corporate Centre Charges should be paid to Westcoast. The 1997 Corporate Centre Charges should be allowed in cost of service in their entirety and the reductions proposed by intervenors rejected.

5.5 BOARD FINDINGS

The Undertaking Applications

5.5.1 The Board observes that the Companies have applied to the Board for approval of the payment of the Westcoast Corporate Centre charges for 1996. However they have also stated that there will be no impact on rates in 1996 as a result of the payment of these charges.

5.5.2 The Board notes that the Companies' Undertakings provide that the Utilities shall receive prior approval from the Ontario Energy Board for any affiliated transaction aggregating $100,000 or more annually. The Board further notes that Westcoast created the Corporate Centre early in 1995 for the purpose of providing services to its affiliates, including Union and Centra. However, the Companies did not make Application for the approval of the affiliated transactions until February 1996, after the nature and level of service and associated charges to Union and Centra from the Corporate Centre for 1996 had already been determined.

5.5.3 The Board finds that according to their Undertakings, the Companies should have obtained prior Board approval before receiving additional services from the Westcoast Corporate Centre beyond those approved in 1995 and that the Board has not been given any explanation as to why such approval was not sought.

5.5.4 The Board notes that there is no rate impact in 1996 resulting from the Corporate Centre Charges and based on the assumption that the services were similar to those proposed for 1997, the Board therefore approves the same level of payment from each Utility for 1996 as it finds appropriate for 1997 later in this Section.

<u>1997 Rate Applications - Westcoast Corporate Centre Charges</u>

5.5.5 The Board is being asked to allow into the Companies' 1997 cost of service, a significant $4.5 million increase in Westcoast Corporate Centre Charges related to a whole package of new services that the Companies claim Westcoast is now providing to Union and Centra. This proposal immediately follows the recent Shared Services initiative by Union and Centra that resulted in a significant $11 million annual decrease in the combined O&M budget of the Companies.

5.5.6 The Board notes that, in some cases, these Shared Services savings relate to the same functional service areas as the proposed cost increases for services from the Westcoast Corporate Centre.

5.5.7 The Board reminds the Companies that the Shared Services initiative was approved by the Board on the basis that, for a one time cost of about $10 million, they would achieve over $10 million savings in O&M costs <u>annually</u> through efficiency improvements resulting from combining certain of the functional operating areas of Union and Centra. Although the Companies informed the Board that the allocation of inter-corporate charges within the Westcoast Group was under study, at no time during the Shared Services initiative did the Companies either attribute any portion of the savings to provision of free services by Westcoast, or its Pipeline Division, or indicate that there would be a future requirement to purchase an additional $4.5 million of Westcoast services in order to maintain the current quality of service to Ontario ratepayers.

5.5.8 Given this background, and the fact that these are significant new charges from the Companies' sole shareholder, the Board agrees with the Companies and many intervenors that there is an unusually heavy onus on the Companies and Westcoast to provide sufficient substantiating evidence to demonstrate the need for, and justify the cost/benefit of, each of the proposed charges.

5.5.9 In this regard, the Board has some difficulty accepting the independence of the expert reviews commissioned by the Companies' management, when these reviews relied on the same experts who assisted Westcoast in its development and application of the cost driver methodology and assessment of the value of the benefits provided to subsidiaries. The exception to this is the KPMG Report that was prepared on behalf of the Companies' Committee of Independent Directors and therefore can be perceived and relied on as a more independent review. Unfortunately this Report was not updated for 1997 and the Companies elected not to call a witness from KPMG.

5.5.10 The Board also finds that the evidence provided by the Companies regarding other regulatory approvals of the Westcoast Corporate Centre Charges, demonstrates clearly that those approvals were based on the approval of specific services that had been accepted in principle, had received prior approval, and found to be required by the LDCs as a paid service from Westcoast. An example is the approval by this Board of Westcoast Treasury Services in E.B.R.O. 486 and E.B.R.O. 489.

5.5.11 The Board notes that, of the regulatory decisions presented by the Companies, only the NEB decisions have approved the cost driver methodology and its use for allocating Corporate Centre Charges to affiliates and that this approval was conditioned. The Ernst and Young study indicates that Corporate Centre Charges to Westcoast Pipeline Division are based on direct assignment or time dockets in many cases. The Board notes also that the NEB had time docket evidence available when it approved the cost driver methodology.

5.5.12 The Board has no conceptual problem with a Corporate Centre approach to shared services, provided the economies of scale and other operating efficiencies of the Centre result in the delivery of required services to Union and Centra on a more cost effective basis than the Companies' own costs of providing the same services. The Board notes that, on a smaller scale, many of the Shared Service savings that Union and Centra have achieved since 1995 were the result of streamlining and combining corporate services.

5.5.13 The Board notes that the Companies' respective Undertakings set out the terms under which the Board shall not withhold approval of an affiliate transaction which are:

- the transaction is shown to be of benefit to the Utility (and not to the detriment of any of its customers);
- a purchase takes place at or below fair market value;
- a sale takes place at or above fair market value; and,
  in the case of Management cost:
- a fair and appropriate allocation amongst the parties of the shared or joint management, administrative and overhead costs.

5.5.14 In considering whether to allow the proposed $5.2 million of Corporate Centre Charges to be included in 1997 O&M costs as part of the cost of service to be recovered from the Companies' ratepayers, the Board has incorporated the above criteria in applying specific tests to each functional component of the proposed Corporate Centre Charges in order to determine whether these are just and reasonable, as follows:

- *Cost Incurrence* - are the proposed Corporate Centre Charges prudently incurred by, or on behalf of, the Companies for the provision of a service *required* by Ontario ratepayers?
- *Cost allocation* - if properly incurred, are the proposed Westcoast Corporate Centre Charges allocated appropriately to the Companies, based on the application of cost drivers/allocation factors supported by principles of cost causality?
- *Cost/Benefit* - do the benefits to the Companies' Ontario ratepayers equal or exceed the costs?

5.5.15 For the first test, Cost Incurrence, the Board has examined the issue of need, ie. is the new, or additional level, of service needed, or is it adequately provided at current levels of service.

5.5.16 For the second test, Cost Allocation, the Board has examined the cost drivers selected by Westcoast and their application to each proposed Corporate Centre Charge based on principles of cost causality.

5.5.17 For the third test, Cost/Benefit, the Board has accepted the four categories offered by the Companies as a basis for assessing quantifiable benefits:

- *Replacement benefits*- the services provided replace an equivalent service at equal or lower cost;
- *Synergistic or linkage benefits* - the services allow the Companies to reduce costs by means of being part of the larger Westcoast group and operating in concert for the procurement of products and services;
- *Revenue enhancement or cost recovery benefits* - the Companies' activities and capabilities provide value to other affiliates for which payment in cash or kind is received;
- *Stand-alone benefits*- strategic actions and activities instituted by the Corporate Centre that produce direct value to the Companies.

5.5.18 In applying these tests the Board has used a sequential "filter" or "screen" approach. Any group of charges that, in the Board's assessment, fails to pass the first screen was found not to be just and reasonable and was not examined further.

Cost Incurrence

5.5.19 In general the Board finds that a primary purpose of the Corporate Centre Charges is for Westcoast to recover, from its subsidiary business units, a significant portion of the Corporate Centre costs that it has decided are necessary for the operation and growth of a diversified energy company. The Board is not convinced by Westcoast's assertion that most components of the charges result from 'bottom up' requests for services from the Companies' managers and budget administrators. The Board's assessment of the evidence is that many of the proposed Charges are a 'top down' allocation of Corporate Centre costs by the sole shareholder and the Westcoast Board of Directors that the Companies' managers are expected to absorb in their budgets.

5.5.20 The Board has considerable difficulty with the notion that any costs that appear to be part of the cost associated with a major shareholder protecting and managing its investment should be allocated to its subsidiaries as a legitimate regulatory expense. Many of the Governance and Executive Charges proposed for 1996 and 1997 appear to fall into this category and the Board in the Norcen E.B.R.O. 314-1-13 Decision has previously disallowed such investment-related costs, based on the fact that the shareholder receives the return allowed by the Board on its investment in the Companies and such carrying costs are for the account of the shareholder.

5.5.21 The Board has concluded that the cost incurrence criterion cannot easily be applied to some of the "services" that lie behind the proposed charges. In several instances the Companies failed to justify, in whole or in part, the need for the new services and there was therefore, no obvious requirement for the services to support the operation of the regulated Utilities. In contrast, charges for Westcoast Treasury services have in the past been properly justified and approved as prudently incurred for the purpose of raising capital for the regulated utility.

5.5.22 The Board finds that the Companies have failed to justify why the Companies need additional Governance services from Westcoast in 1996 and 1997 over and beyond the 1995 level and hence, why the shareholder should be paid for claimed Governance services benefits over and above the allowed return on common equity. The proposed charges in this group include Westcoast Executive Costs and Westcoast Directors Expenses.

5.5.23 Union and Centra have 60 highly qualified and well compensated senior managers out of a total of 103 in the Westcoast group of regulated companies. The Companies' internal Senior Management budget will cost Ontario ratepayers over $7 million in the test year. In the Board's view, the Companies have not justified an additional requirement for over $1 million of Executive support from Westcoast. The Companies' argument that they are "thin" after the Shared Services initiative and that Westcoast Executives provide a "safety net" was not adequately supported with concrete examples to substantiate either the need for, or the level of, the proposed Executive Charge.

5.5.24 With regard to Westcoast Board of Directors' Expenses, the Board notes again that the Companies have their own Board of Directors, including Westcoast Officers, to whom they pay fees and expenses in return for governance services from the Directors. The separation of the governance role between Directors and Officers is difficult and the Board, in the absence of other evidence, must assume that the Westcoast Directors/Officers on the Companies' board(s) provide all the additional governance that is needed. The Companies have provided insufficient justification of the need for additional governance by, and hence for paying a portion of the fees paid to, Westcoast Directors.

5.5.25 The Board finds that the Westcoast Board of Directors' Expenses are a cost properly incurred by Westcoast as part of managing its investment in its subsidiaries, including Union and Centra, and the allowed return on common equity invested in Union and Centra appropriately compensates the shareholder for any additional indirect governance the Westcoast Directors may provide.

5.5.26 For the above reasons, the Board will not approve inclusion of $1,162,000 of proposed new charges for Westcoast Executive costs and Directors' Expenses in the Companies' 1997 test year cost of service.

5.5.27 In order to assist the Companies, the Board notes that, had it proceeded to examine the proposed Westcoast Executive costs under the cost allocation test, it would have had difficulty with a cost driver methodology that produces the result of allocating over $1 million of Westcoast Executive costs to Union and Centra which already have 60% of the Senior Managers in the total Westcoast regulated group of companies. Intuitively there should be an *inverse* cost causality relationship between the number of executives in an affiliate and the allocation of executive time and costs from the parent.

5.5.28 The Board also notes that, had it proceeded to examine the proposed Westcoast Executive costs under the benefit/cost test, there is no evidence of a tangible positive benefit to justify these costs as a legitimate utility cost of service, such as might be evidenced, for example, by an equivalent incremental reduction in the Companies' internal $7 million budget for Senior Management costs. The Shared Services initiative had as one key element a reduction in executive head count as a result of combining the executives of the Companies. This resulted in an annualized cost saving of $893,000. No such test year saving is offered here. The Companies claimed as a stand alone benefit from Westcoast, a portion of the savings from the Shared Services initiative between the Companies. The Board rejects this claimed benefit, since the project management was undertaken by the Companies' managers and the one time costs of $9.6 million were paid directly by the Utilities' ratepayers.

Cost Allocation

5.5.29 For functional areas of the Westcoast Corporate Centre Charges that did not fail the first test, based on a possible identified need for the service, the Board has conducted an examination of the *cost allocation* proposed by Westcoast as modified by the recommendations of the KPMG Report.

5.5.30 The Board finds that the cost driver approach employed by Westcoast is a logical and structured methodology that has a basis in cost causality principles. The actual cost drivers selected by Westcoast are in themselves, when viewed in isolation, also reasonable and quantifiable. However, in the Board's view, the application of the selected cost drivers and the underlying assumptions about the nature of the costs and the activities that caused the costs, requires considerable judgement.

5.5.31 Although the Board has not rejected outright any of the proposed Corporate Centre Charges based purely on its disagreement with the selected cost driver and its application to a particular functional area, in order to be of assistance to the Companies, it has decided to indicate the areas where, in its view, the methodology is either unsupported by adequate evidence of cost causality or the end result is counter intuitive.

5.5.32 A major difficulty the Board finds in the methodology is the apparent use of Rate Base/fixed assets as a default. In the Board's view, Rate Base/fixed assets is an indicator of the *size* of a subsidiary, but not necessarily of cost causality for certain Westcoast activities, or the contribution to the growth in earnings and shareholders equity that are the primary focus of most senior corporate executives. An example is Corporate Planning and Development that according to the evidence, is aimed at growth of the Strategic Business units of Westcoast. The Board's review of the

Westcoast Annual Reports and other public information issued by, or written on, Westcoast indicates that the regulated distribution utility area is not the primary area of growth in Westcoast's earnings and return on equity (in percentage terms), or the primary focus of new business development, but is a relatively stable base of income and return on equity.

5.5.33 The Board, while not advocating its reinstatement, suggests that time docketing provides more direct links. Time docketing may also provide a means of validating the use of a particular cost driver for allocating Corporate Centre Charges, such as those in Corporate Planning and Development. In order to be valid, a cost driver allocation should yield substantially the same result as a time docket, or other measured basis for direct assignment of costs. The Board notes that in this proceeding, the Companies justified their use of the number of bills as a cost driver for allocating Centra's customer accounting costs, based on a time docketing study.

5.5.34 The Board cannot therefore completely accept the application of the Westcoast's current cost driver approach to the Companies and notes in addition to examples previously cited, the following areas where the cost drivers selected, or their application, require further validation based on cost causality principles:

- AGM/Annual Report; and
- Corporate Communications.

5.5.35 The Board also finds that the cost driver approach, as applied, gives insufficient financial recognition of the 'two way street' i.e. the costs associated with the contributions that the Companies make to the business development strategies and operating practices of the Westcoast group. In many cases these are also claimed as *revenue enhancement benefits*, but in most cases no direct compensation is received by the Companies.

5.5.36 For the above reasons the Board finds inadequate justification in many of the functional areas for the quantum of Westcoast Corporate Centre Charges proposed to be levied on the Companies in the test year. As noted previously the Board has not rejected outright any of the proposed Corporate Centre Charges purely on its disagreement with the selected cost driver and its application to a particular functional area. However, the Board also notes that this lack of cost substantiation makes an assessment of the benefit/cost ratios extremely difficult because the costs allocated to Union and Centra are often not appropriately supported and hence for this reason the benefit/cost ratio equations cannot be relied upon.

Benefit/Cost

5.5.37 The Board has reviewed the Companies' evidence on the quantifiable *benefit/cost* of the Direct Services and Access to Capital services that underpin the Westcoast Corporate Centre Charges. In addition, certain functions under the area of Governance that have some reasonable evidence of having been required by the Companies for service to ratepayers have been examined.

5.5.38 In the case of clear evidence of a *replacement benefit* the Board is prepared, in principle, to accept the costs as a regulatory expense, provided the service is required to serve the ratepayers of the regulated utility and the supporting information demonstrates clearly that, either there is a direct net operating cost reduction, or the Companies' avoided cost of alternatives, such as third party out sourcing of the service, are more costly than the service provided by Westcoast.

5.5.39 Where the costs are justified based on a *synergistic/linkage benefit*, the Board will accept the costs, if again, the supporting evidence clearly indicates the service is required to serve the Utilities' ratepayers and the Companies' forecast costs, including the charges from Westcoast, are lower than if they proceeded independently, for example in the procurement of the Microsoft Office Software. The Board notes however, that in this example, the Companies are the largest block of software users and accordingly the incremental benefit received is lower, and the allocated Westcoast management cost higher, than that of smaller Westcoast affiliates. The Companies do not appear to have received any offsets or other consideration from being the largest block underpinning the volume discount.

5.5.40 In the case of *revenue enhancement or cost recovery benefits,* the Board wishes to ensure that the receiving affiliate pays the fully allocated cost of the service provided by the Companies and that there is a direct financial compensation to the Companies' ratepayers. In the Board's view it is inappropriate to list such a benefit unless it meets these criteria. The main example of such a benefit in the test year is the recovery of $140,000 for the services provided to the Corporate senior officers committee by the Companies' Chief Executive Officer and Executive Vice-President.

5.5.41 In the case of a *stand-alone benefit* the Board requires clear evidence that not only was the initiative developed by the Westcoast Corporate Centre, but that the project that resulted in the savings to the Companies' ratepayers utilized Westcoast management time equivalent to the charges from the Corporate Centre.

5.5.42 In several service areas the Board has found that the benefits claimed by the Companies are overstated or inadequately substantiated. Accordingly, in the Board's view, the benefit must be discounted more than what the Companies' experts suggest. Account should also be taken of the "two way street" by recognizing the significant pool of expertise and experience resident in the Companies and the benefits that this pool provides to both the parent and other affiliates.

5.5.43 The Board has set out its specific findings under each of the Companies' three main service/charge groupings - Direct Services, Access to Capital and Governance.

Direct Services

5.5.44 Based on a careful review of the benefit/cost information filed in this case the Board finds insufficient justification of the benefit to Ontario ratepayers from a significant part of the Corporate Centre Charges in the Communications and Planning and Development functional areas. For other Direct Services the Board found the benefit or cost to be overstated and has either discounted the benefit or reduced the cost to a level deemed reasonable. The net result is that the Board finds $1,010,000 of the Direct Services component of the proposed 1997 Corporate Centre Charges to be just and reasonable for inclusion in the 1997 test year cost of service. These costs are to be allocated $723,100 to Union and $286,900 to Centra.

Access to Capital

5.5.45 Based on a careful review of the benefit/cost information filed in this case the Board accepts in full the charges for Treasury Services, but finds insufficient justification of the benefit to Ontario ratepayers from all or a significant part of the Corporate Centre Charges in the functional areas of AGM/Annual Report and Trustee Fees. For other components of Access to Capital services the Board found the benefit or cost to be overstated and has either discounted the benefit or reduced the cost to a level deemed reasonable. The net result is that the Board finds $899,000 of the claimed Access to Capital component of the proposed 1997 Westcoast Corporate Centre Charges to be just and reasonable for inclusion in the 1997 test year cost of service. These costs are to be allocated $660,500 to Union and $238,500 to Centra.

Governance

5.5.46 The Board has already found that the proposed Executive costs and Directors' Expenses have not been justified.

5.5.47 The Board finds the cost of the proposed Legal & Consulting Fees and Audit Fees to be inadequately supported, but has not reduced the allowed budget, since these costs are to be billed as direct charges. It directs the Companies to include these functional areas under Direct Services and to report on the actual versus budget cost and the specific services provided in the next rates case. The Board will then use this information to make a determination of the prudence and reasonableness of the services and charges with regard to allowance of any similar costs for 1998.

5.5.48 The Board finds the corporate Legal benefit/cost ratio to be overstated and has discounted the benefit to a level deemed reasonable.

5.5.49 The net result is that the Board finds $347,000 of the Governance component of the proposed 1997 Corporate Centre Charges to be just and reasonable for inclusion in the 1997 test year cost of service. These costs are to be allocated $259,500 to Union and $87,500 to Centra.

Additional Findings

5.5.50 The Board is not convinced by the Companies' arguments that because overall O&M costs have only increased by 3.4% since 1995, it necessarily follows that, the Corporate Centre Charges are all prudently incurred as part of a conservative test year O&M budget. The Westcoast Corporate Centre Charges in some cases, clearly comprise an additional layer of overhead costs; for example, the Companies' executive costs would have increased in part as a result of the proposed Westcoast Corporate

Centre Charges, from $6.506 million (1995 actual) to $8.245 million in 1997, despite an inter-Company Shared Services annual saving of $893,000.

5.5.51 The Board reiterates that the burden of proof to justify significant new affiliate costs rests with the Companies and Westcoast. It is also their responsibility to maintain service to their customers and not to suggest as they have in argument, that, if some or all of the Westcoast Corporate Centre Charges are not allowed in the cost of service and the Utilities are not given the means to pay for all of the proposed Corporate Centre services in 1997, then the Utilities will be faced with the prospect of either eliminating services with detrimental impacts on quality of service, or asking the shareholder to continue to cross-subsidize the provision of services in Ontario.

5.5.52 It is the Board's view that the only significant change in the area of Westcoast affiliate transactions since its E.B.R.O. 486 and E.B.R.O. 489 Decisions which were issued before the Westcoast Corporate Centre was operational, is that the NEB directed the Westcoast Pipeline Division to recover the costs of services provided to affiliates from those benefitting from those services. The Board has no evidence to indicate that the Westcoast Pipeline Division was either providing free services to Union and Centra in 1995, or that the quality of service to Ontario ratepayers was dependent on such free services.

5.5.53 The Board directs the Companies to undertake a complete documentation of all of the Westcoast Corporate Centre *Direct Services* that they receive in 1997 and the actual direct cost savings that were realized and to report on a year to date basis in the next main rates case(s). In the area of *Access to Capital* the Companies must better justify all charges, other than Treasury Services, on the basis of the direct avoided costs relative to the 1995 level of service, before the Board will consider these further. The Board remains unconvinced that the shareholder's costs related to *Governance* of the utility operations of Union and Centra, other than the Direct Services previously noted in the Board's Findings, are not compensated for adequately in the shareholder's return on the equity deployed for the provision of utility services. It continues to view these as costs associated with managing a diversified holding company, and an additional layer, rather than a replacement for the Companies' own governance structure, which is in place and paid for by the Utilities' ratepayers. If special external legal services or audit services are needed by the Companies to support their governance, then as in the past, the procurement of these should be on a competitive basis with direct invoicing to the Companies.

5.5.54 Finally, the Board is not prepared to consider the Corporate Centre services either as a repetitive affiliate transaction under the Companies' Undertakings, or as a single affiliate transaction for blanket approval, just because they originate from, or are coordinated by, one affiliate service provider. The Board directs the Companies to make application for any further Westcoast Corporate Centre services in 1997 within the framework of their respective Undertakings.

5.5.55 The Board also directs the Companies to apply for 1998 approval for all Westcoast Corporate Centre affiliate service transactions by each functional area and to justify each according to its financial benefit/cost to the ratepayers in each successive test year.

Summary

5.5.56 The Board accepts $2,256,000 out of the Companies' claimed $5.2 million of Westcoast Corporate Centre Charges as meeting its criteria for inclusion in the Companies' 1997 test year cost of service. This represents a 325% increase in Corporate services from Westcoast. Of this amount $1,643,100 is to be recovered as part of Union's 1997 cost of service and $612,900 as part of Centra's 1997 cost of service.

5.5.57 The details of the Board's Findings on the 1997 O&M expense of the Companies by each functional area of the proposed Westcoast Corporate Centre Charges are shown in Table 5.3.

Table 5.3: Board-Approved Westcoast Corporate Centre Charges to the Companies for 1997

Board-Approved Westcoast Corporate Centre Charges to the Companies for 1997 ($000's)				
Service/Charge	**UNION**		**CENTRA**	
	1997 per Union	**1997 per Board**	**1997 per Centra**	**1997 per Board**
DIRECT SERVICES				
IS Technology	265.3	225.0	82.7	70.0
Human Resources	151.3	113.0	89.7	67.0
Communications	354.0	94.6	113.0	30.4
Taxation and Audit	165.8	165.8	55.2	55.2
Risk Management	36.0	36.0	35.0	35.0
Planning & Development	170.7	88.7	56.3	29.3
Subtotal	***1,143.1***	***723.1***	***431.9***	***286.9***
ACCESS TO CAPITAL				
Treasury	456.0	456.0	168.0	168.0
Corporate Controller	256.7	92.0	85.3	33.0
Other				
-Investor Relations	276.7	112.5	92.3	37.5
-Trustee Fees	203.4	0.0	67.6	0.0
-AGM/Annual Report	263.5	0.0	88.5	0.0
Subtotal	***1,456.3***	***660.5***	***501.7***	***238.5***
GOVERNANCE				
Executive	831.2	0.0	190.8	0.0
Legal	229.3	109.0	77.7	37.0
Other:				
-Legal & Consulting Fees	134.2	134.2	44.8	44.8
-Directors Expenses	104.8	0.0	35.2	0.0
-Audit Fees	16.3	16.3	5.7	5.7
Subtotal	***1,315.8***	***259.5***	***354.2***	***87.5***
TOTALS	**3,915.2**	**1,643.1**	**1,287.8**	**612.9**

6. GAS COSTS AND RELATED MATTERS

6.0.1 Since September 1995, as a result of the Shared Services initiative, the Companies' gas supply portfolios have been jointly managed. The Companies requested approval for the following aspects of their gas supply management for 1997:

- Forecasting Methodology;
- Quarterly Rate Adjustment Mechanism;
- PGVA and Related Gas Supply Variance Account Trigger Levels;
- Gas Purchasing Procurement Policies and Risk Management;
- Transportation Plans; and
- Gas Supply Portfolios.

6.0.2 The changes that have resulted from the Shared Services initiative are described under the relevant sub-hearings.

6.0.3 For Union the following general terminology applies to its gas costs.

WACOG - the weighted average unit cost of all of its gas supplies including spot gas delivered in Ontario.

PGVA - purchased gas variance account. Once WACOG is approved, it becomes the reference price for this account and variances are recorded in this account as approved. Variances in actual transportation tolls are also captured in this account. Once the actual accumulated balance or the forecast year-end balance in the PGVA exceeds a one-time charge or credit of $10 to a typical residential system gas customer, Union is required to submit a report to the Board including an application for changes in rates or reasons why an application is not appropriate.

6.0.4 For Centra the following general terminology applies to its gas costs.

Firm WACOG - The forecast weighted average unit cost of all of its long-term gas supplies at the Alberta border.

Firm PGVA - The reference price for this variance account is the Board-approved firm WACOG and variances from it are recorded in this account.

Gas supply related variance accounts These accounts are used to record variances in other gas costs including spot gas and transportation tolls from approved levels. They are set out in detail in Chapter 8, Deferral and Variance Accounts.

Centra is similarly required to report to the Board whenever either the accumulated balance or forecast year-end balance in all of Centra's gas supply related variance accounts reaches $10 per typical residential system gas customer.

6.1 BACKGROUND

6.1.1 In its February 1994 E.B.R.O. 485-02, 476-06 and 483/484 Joint Partial Decision with Reasons - Cost of Gas, the Board approved gas supply contracts for the three major Ontario local distribution companies ("LDCs") in which forecast prices were based on indices rather than fixed prices. In its Decision the Board indicated that it was uneasy relying on forecasts based on indices for the purpose of ratemaking. However, as a transition measure, the Board was prepared to accept the new forecasting methodology. The Board stated that it would continue to hold the shareholder accountable for the reasonable accuracy of forecasts.

6.1.2 Since that time, in order to ensure that rates reflect forecast and actual changes in gas costs, the LDCs have made frequent applications to the Board for changes in rates and the disposition of balances in gas supply related variance accounts. In an attempt to mitigate the deleterious impacts and the regulatory burden of the frequent rate changes and retroactive one-time debit or credit adjustments to ratepayers accounts, the Board has approved, among other things, a Quarterly Rate Adjustment Mechanism ("QRAM") for Centra and changes to Union's gas cost forecasting methodology.

6.1.3 In its June 1995 E.B.R.O. 489/E.B.R.L.G. 34-14 Decision with Reasons - Part II, the Board noted that "annual rates for Centra, to the extent that they can reasonably reflect the cost of gas, appear to be a thing of the past." The Board noted that while many parties argued that a fundamental reform of the regulation of gas costs may be necessary they also urged that any changes be delayed until there could be a complete review of the operation of gas markets. The Board agreed that a fundamental reform of the regulation of gas costs might be necessary and, as a result of the Board's recommendations in that Decision, the Ten Year Market Review, which has been described in Chapter 11 in this Decision, was undertaken. In the meantime, the Board approved a QRAM for Centra. The Board found that it had jurisdiction to adjust Centra's rates in this manner as long as the adjustments were based on mathematical formulae and did not require discretionary decision making by the Board.

6.1.4 Under the QRAM, each quarter Centra notifies the Board and intervenors in Centra's last rates case of changes in the twelve month forward forecast of its firm WACOG. If Centra's quarterly forecast of its forward twelve month firm WACOG shows a change of greater than $0.05/GJ, Centra files for a quarterly rate adjustment on a prospective basis. Unless a party objects, Centra's rates are varied without a hearing, written or oral. Centra's firm PGVA and buy/sell reference prices are adjusted at the same time. In this proceeding, Union proposed that it would implement a similar QRAM.

6.1.5 Under the QRAM, variances continue to accrue in Centra's firm PGVA until the reference price is changed as the result of an approved quarterly rate adjustment. The balances that have accrued in the firm PGVA until the change are not considered for disposition until they reach the "trigger" point, currently the equivalent of $10 per residential system gas customer, on a cumulative basis for all of Centra's gas supply related variance accounts, or until Centra comes before the Board in a main rates case.

6.1.6 The disposition of balances in gas supply related variance accounts and the "trigger" point are dealt with under the subheading *PGVA and Related Gas Supply Variance Account Trigger Levels*.

6.2 FORECASTING METHODOLOGY

6.2.1 In its June 1995 E.B.R.O. 489-Part II Decision the Board noted that for 1995 Centra based the indexed portion of its gas cost forecast on the most recent 30 day average for New York Mercantile Exchange ("NYMEX") price quotations for the months of January to December 1995. In the E.B.R.O. 489 proceeding Centra initially compared those forecasts to those of an independent consultant. It subsequently compared them to Union's consensus forecasts.

6.2.2 The Board in its E.B.R.O. 489-Part II Decision stated that it had a preference for a Canadian-based index but that, absent liquidity in Canadian markets, it would accept the NYMEX-based index as a suitable substitute.

6.2.3 In its E.B.R.O. 486 Decision, the Board approved a change in Union's gas cost forecasting methodology which was based on a forecast utilizing a consensus of five independent forecasts rather than on indices such as NYMEX. In approving the methodology the Board noted that the independent forecasters took note of NYMEX and other indices and applied judgement in developing their forecasts. The Board again noted that ultimately the forecasts are Union's forecasts and Union continues to be accountable for forecast accuracy.

6.2.4 The Utilities' most recent forecasts of gas costs were dated January 31, 1997. They reflected the December consensus forecasts for gas supplies at Henry Hub, Louisiana and at Empress, Alberta ("the Alberta border") for twelve months commencing March 1, 1997.

6.2.5 Parties to the ADR Settlement Agreement accepted the Utilities' methodology for forecasting their 1997 costs of gas based largely on Union's consensus forecast approach set out above.

6.2.6 Union's original gas supply evidence was pre-filed on May 10, 1996. Since that time Union has revised its forecast cost of gas four times: as of August 30, 1996; twice in November 1996 - once in an "update" and once in "Revised" evidence; and in its January 27, 1997 Notice of Motion.

6.2.7 In order to put in place rates which reflected Union's changes in gas cost forecasts the Board has issued two Interim Rate Orders, E.B.R.O. 494-01 on December 24, 1996 and E.B.R.O. 494-02 on February 17, 1997.

6.2.8 Centra also pre-filed its forecast cost of gas for 1997 on May 10, 1996. Since that time it has:

- received a quarterly rate adjustment (E.B.R.O. 489-04) based on its forecast cost of gas for the twelve month period commencing July 1, 1996;
- revised its forecast cost of gas once in August, twice in November (once to reflect the ADR Settlement Agreement), again in December in support of a Quarterly Rate Adjustment for the twelve month period commencing January 1, 1997 and again in January, 1997 in support of a "quarterly" rate adjustment which Centra requested be implemented a month early for the twelve month period commencing March 1, 1997; and
- the Board has issued two Interim Rate Orders, E.B.R.O. 493-01 on December 24, 1996 and E.B.R.O 493-02 on February 17, 1997 in order to put in place rates which reflect Centra's revised forecast costs of gas.

Board Findings

6.2.9 The Board is very concerned about the recent frequent rate changes and retroactive adjustments to ratepayers bills. They come about as a result of the Utilities' constantly changing forecasts of the cost of gas, which in turn result from the fact that the Utilities' gas costs are largely driven by indexed pricing which in turn reflects the market volatility of gas prices. These changes and adjustments change gas prices for customers in what they perceive to be a random manner, especially when they are upward, and given what the Companies have told the Board about customers' proclivity not to read explanatory customer notices.

6.2.10 The Board observes that, even with the implementation of a QRAM, rate changes cause rate instability and impose a regulatory burden on the ratepayers, the Board, the Utilities, buy/sell customers and their ABMs and make planning for gas costs difficult for the Utilities' ratepayers.

6.2.11 Even with the frequent changes, the regulatory process results in a lag in implementing rates that reflect updated forecast gas costs and therefore market prices, and timely and accurate market signals are not received by customers.

6.2.12 The Board notes that, under the current regulatory regime changes in gas costs, resulting from changes in the Companies' forecasts are passed through to ratepayers and the Utilities do not generally earn a margin on gas commodity sales. While the Utilities have a professional incentive to be accurate in their gas cost forecasts they do not have a monetary incentive to be accurate.

6.2.13 The volatility in the cost of gas resulting from gas purchase contracts based on indices is unlikely, in the Board's view, to significantly moderate in the near future. The Board recognizes that the outcome of the Ten Year Market Review may mitigate or end these concerns. In the meantime, in the Board's view, steps should be taken to ensure that constant rate changes due to volatility are minimized and the lag between changes in forecast costs of gas and implementation of rates reflecting any change in the forecast is reduced. To this end the Board expects the Utilities to file in their next main rates cases proposals which would minimize rate changes resulting from changed gas cost forecasts and expedite the implementation of rates reflecting these changes.

6.2.14 The Board has offered some suggestions under this sub-heading and under the sub-headings Risk Management and Quarterly Rate Adjustment Mechanism to assist the Utilities in developing proposals. The Board emphasizes that these are only suggestions and are not prescriptive nor an indication of the Board's view of which changes are appropriate.

6.2.15 In order to address the lag in implementing rates to reflect changes in the cost of gas, one alternative could be to forecast a level of gas costs and a tolerance band. The Utilities could then adjust rates on a regular basis (and the buy/sell reference price, as is currently done on a monthly basis for Consumers' Gas' direct purchase customers) as long as gas costs were within this tolerance band. Should the actual gas costs fluctuate outside of the tolerance band, then the Utilities could make an application to adjust its gas costs and tolerance bands. Alternatively, the differences could be shared between ratepayers and shareholders in some proportion at the time of disposition. In this regard the Board notes that under ABC Service (which is dealt with in Chapter 11 - Direct Purchase), the ABMs would be at risk for changes in gas costs (depending on their contractual arrangements), and if that service is implemented it may be appropriate to consider whether the Companies should assume similar risks for changes in gas costs.

6.2.16 The Board notes that, if the ABC Service approved by the Board in this Decision is implemented, changes in the commodity cost of gas would be passed through to ABC customers without a public hearing as frequently as every quarter. As a result, more customers will be in a situation in which their rates will reflect their actual cost of gas.

6.3 QUARTERLY RATE ADJUSTMENT MECHANISM

6.3.1 Union proposed the implementation of a QRAM similar to Centra's on the grounds that such a mechanism would provide a "predictable adjustment mechanism for dealing with increases or reductions in costs on a timely basis ... introduce process efficiencies within the Union/Centra organization [and] ... avoid the cost of a hearing in most cases."

6.3.2 The Utilities proposed that the threshold amount for a quarterly rate adjustment application be increased from $0.05/GJ presently approved for Centra to $0.10/GJ. They stated that this would be consistent with the Utilities' proposal to change Union's PGVA "trigger" amount and Centra's gas supply related variance trigger amounts from $10 to $25 per residential system gas customer.

6.3.3 Parties to the ADR Settlement Agreement supported Union's proposal to implement a QRAM but did not come to agreement on the Utilities' proposed threshold of $0.10/GJ for applications under the QRAM.

Positions of the Parties

6.3.4 The Utilities' position was that the proposed $0.10/GJ threshold for quarterly rate adjustment represented about $10 per residential system gas customer on an annual basis and that raising the threshold to this level would "dampen short term volatility effects."

6.3.5 Board Staff noted that the use of consensus forecasts for forecasting gas costs was intended to overcome the tendency of forecasts based on indices to reflect rapid and regular swings in gas prices. If the consensus forecasts produce this result, they argued, then there should not be a need to worry about frequent swings in forecast gas costs and therefore, a $0.05/GJ threshold would not give rise to frequent applications for gas cost changes.

6.3.6 In addition, Board Staff argued, a change to a higher threshold for quarterly rate adjustment may result in a risk that the buy/sell price will be less representative of the price the Utilities are paying for system gas. NCL argued the same point.

6.3.7 In Board Staff's view, there was insufficient evidence to justify a change in the threshold for a quarterly rate adjustment. Direct Energy and PanEnergy agreed with this position.

6.3.8 Direct Energy and PanEnergy also argued that the $0.05/GJ threshold should be maintained, because it allows interested parties to track the Utilities' actual cost of gas.

6.3.9 London GasSave expressed concern that, to the extent that the Utilities compete with direct purchase suppliers, a higher threshold would give the Companies more discretion in deciding when, or when not, to implement gas costs changes depending on the advantage to the Companies.

6.3.10 IGUA and NRG argued for the retention of the $0.05/GJ threshold for quarterly rate adjustments on the ground that it would keep gas costs closer to actual gas costs.

6.3.11 In reply, the Utilities argued that the Board should be concerned about the impact that frequent rate changes have on customers. They submitted that the proposal to raise the threshold to $0.10/GJ balances the concern about frequent rate changes with the need for timely rate changes to reflect the most up-to-date gas cost forecasts.

Board Findings

6.3.12 The Board observes that, under the Utilities' proposals for gas cost adjustments, there are two potential adjustments that could occur as a result of changes in forecast and actual gas costs. Centra's QRAM, in the absence of any objection, changes rates, without a hearing, on a prospective basis to reflect forecast changes in firm WACOG for the next twelve month period. Variances in actual gas costs from Board approved forecast gas costs would continue to be recorded in the appropriate gas supply variance/deferral accounts to be disposed of generally on a retroactive basis. Since the disposition of the balances in those accounts is subject to the Board's discretionary judgement, the final disposition must be subject to a hearing, either written or oral.

6.3.13 Under Centra's QRAM, balances continue to accrue in the gas supply deferral accounts to the extent that monthly actual gas costs vary from Board approved forecast costs. When a quarterly rate adjustment is implemented new reference prices for the gas supply deferral accounts are set and accruals will reflect variations from the new prices. To the extent that gas costs vary from the new prices the variations will continue to be captured in the relevant gas supply deferral accounts. If these new entries do not offset existing entries, credit or debit balances will continue to grow and the Board must be concerned since, when the balances are disposed of, ratepayers may be subject to large adjustments in their gas costs that are retroactive in nature.

6.3.14 The Board notes that the parties to the ADR Settlement Agreement agreed that the Utilities need not make application for the disposition of the balances in their gas supply deferral accounts until the forecast balances reach the point where they represent $15, as opposed to $10 per residential system gas customer by fiscal year end. The Board is concerned that the change to a higher trigger may exacerbate the accumulation of balances problem set out above.

6.3.15 If the Board were to approve the gas cost increase threshold of $0.10/GJ for a quarterly rate adjustment then, to the extent that the forecast cost of gas is not correct and balances continue to accrue in the relevant gas supply variance accounts, these balances will accrue to a higher level before a change is made than if the threshold is maintained at the current $0.05/GJ level.

6.3.16 In this regard, the Board notes that Centra has used the QRAM three times since its last rates case, and has accrued large balances in its gas supply variance accounts that must be dealt with in this proceeding. The Board deals with PGVA Balances under the sub-heading *PGVA and Related Gas Supply Variance Account Trigger Levels*.

6.3.17 In addition, the Board observes that under the QRAM, Centra applied for an adjustment to be effective July 1, 1996 of $0.04/GJ in its firm WACOG in E.B.R.O. 489-04 (that application also included a rate change to reflect a change in TCPL tolls) and $0.03/GJ to be effective January 1, 1997 in E.B.R.O. 493-01. The level at which these applications were made appears to belie the Utilities' concerns about frequent rate changes and be counter to the proposal to change the threshold for quarterly rate adjustments from $0.05/GJ to $0.10/GJ.

6.3.18 The Board observes that parties to the ADR Settlement Agreement agreed upon Union's proposal to update gas cost prices quarterly.

6.3.19 The Board notes that the QRAM for Centra applies to its firm WACOG, which is based on firm supplies at the Alberta border. Union on the other hand calculates its WACOG based on all of its gas supplies, including spot gas, delivered to Ontario. The issue for the Board is whether the same threshold should be applied to the proposed QRAM for Union. The Board is persuaded that in the case of Centra, the threshold should remain at $0.05/GJ in order to achieve a balance between limiting the number of rate change applications and maintaining a close correspondence between actual gas costs and the cost of gas reflected in rates.

6.3.20 The Board observes that Union did not provide any details on how it intends to implement the QRAM, for example, whether the calculation of the threshold for a quarterly rate adjustment application will be based on Union's forecast WACOG or forecast Alberta border firm supply price or prices based on some other combination of supplies. An adjustment mechanism based on an Alberta border price may need to reflect smaller variations than one based on an Ontario delivered price that includes spot gas. Depending upon the choice, it appears to the Board that the threshold may need to be substantially different from that appropriate for Centra. While the Board approves in principle a QRAM for Union, since Union has not provided the above noted details, the Board does not approve the implementation of the QRAM for Union at this time.

6.3.21 The Board observes that a QRAM was intended to be based on a mathematical formula that does not require any discretionary judgement on the part of the Board. This would ensure that the Board was acting within its jurisdiction and also ensure that quarterly rate adjustments were made on an expeditious basis. The Board has addressed its concerns about the transparency of the process in its E.B.R.O. 493-02/494-02 Interim Rate Orders in which it said:

The Board finds that although the rate adjustments are reasonable based on the information provided in Centra's prefiled evidence, it is of the view that the formulistic approach involved under the Quarterly Rate Adjustment Mechanism requires a greater level of transparency to provide sufficient detail on the methodology for forecasting the gas costs and rate changes. This will enable the Board and interested parties not only to review the pricing changes, but to apply those pricing changes in a meaningful way to volumes received from Centra's various supply categories. The Board expects that Centra will consult with Board Staff and interested parties to improve the detail provided in future cost of gas applications.

6.3.22 The Board notes Union received approval of a consensus gas cost forecast methodology in E.B.R.O. 486. This methodology was intended to overcome the tendency of forecasts based on indices to overreact to rapid and regular swings in gas prices. To improve process efficiencies between the Companies, Centra adopted the same methodology. However, as noted previously, the QRAM was approved as a mathematical formula that did not require discretionary decision making by the regulator. The consensus forecast methodology involves the blended judgements contained in five independent market forecasts, and is consequently more readily open to challenge by participants, and less amenable to the mathematical formula approach required under Centra's QRAM.

6.3.23 In addition, the Board observes that such consensus forecasts may not provide the most timely information, as evidenced by the fact that the January 27, 1997 gas cost applications were based on December 1996 consensus forecasts, while NYMEX 30 day strip would have included information on a large part of the January 1997 trading activity. The Board is also of the view that Centra's use of a month of trading activity, as opposed to an observation on a specific day, addresses some the concerns associated with price volatility. It should be noted that at the end of the day, under indexed contracts, it is the index price that the Utilities will pay, regardless of price volatility, and having rates which reflect this should limit accumulations in the Companies' gas cost deferral accounts.

6.3.24 The Board directs the Companies to prepare an analysis for the next main rates case of the accumulated balances in the PGVA using the consensus forecasting methodology, and another using the indices reflected in actual contracts. Such information may be useful in enabling parties to objectively assess the relative merits of the two approaches. If the differences are not substantial the Board may consider the use of quarterly rate adjustments based on one or more indices.

6.3.25 In summary, the Board accepts in principle the use of a QRAM by Union. However, since the details of Union's mechanism have not been articulated, the Board directs Union to proceed by way of a similar process as was followed for the E.B.R.O. 494-02 Motion until such time as the Board is satisfied that the process is sufficiently transparent to be adopted as a QRAM.

6.3.26 The Board accepts the continued use of the QRAM by Centra, subject to its directions in E.B.R.O. 493-02 and E.B.R.O. 494-02, that the Companies work with Board Staff and interested parties to improve the transparency of quarterly rate adjustment applications. The Board further directs that the threshold trigger for Centra remain at $0.05/GJ.

6.3.27 In order to streamline the operation of the QRAM the Board is of the view that the Companies' rate schedules could be amended so that any gas cost related charges which would need adjustment as a result of quarterly rate adjustment approval are transferred to an appendix, with the rate schedules providing the relevant cross-references. In order to expedite the process it may be appropriate to exclude items such as carrying costs of inventory from these appendices. The Board directs the Companies to address the merits of this proposal in their next main rates cases.

6.3.28 The Board is also of the view that if the QRAM is truly mechanical and transparent, parties may not need an opportunity to object to proposed gas cost changes. Based on the experience gained over the past two years with Centra's QRAM, prior to the introduction of the consensus forecast methodology, the Board is of the view that the comment process has generally not resulted in any significant challenges to Centra's proposed gas cost adjustments. In light of this experience, and the opportunity of parties to raise concerns at the time of disposition of related deferral account balances, the Board invites intervenors to advise it on the need for them to comment on quarterly rate adjustment applications. However, where proposed changes are based on forecasts which involve judgement the Board believes that the opportunity to comment before making any rate changes is a necessity.

6.4 PGVA AND RELATED GAS SUPPLY VARIANCE ACCOUNT TRIGGER LEVELS

6.4.1 In the E.B.R.O. 485-02, 476-06, 483/484 Joint Partial Decision with Reasons - Cost of Gas, the Board determined that, in order to ensure that large balances in the LDCs' purchased gas deferral accounts do not arise as a result of gas market price volatility, the LDCs should notify the Board whenever the balances in the "combined relevant deferral account or accounts, combined with the toll variation accounts" are forecast to exceed a one-time charge or credit of $10 per residential system gas customer at year end. The notification was to include either an application for changes of rates or a recommendation as to why an application would not be appropriate. The Companies proposed to increase the trigger level to $25.

6.4.2 Parties to the ADR Settlement Agreement who participated in the discussion of this issue agreed that the trigger levels for Union and Centra should be increased from $10 to $15 per residential system gas customer effective January 1, 1997. Parties to the

ADR Settlement Agreement stated that a $15 trigger represents a compromise between the current $10 and the Utilities' proposal of $25. The parties also stated that a $15 threshold addresses concerns about the frequency of reviews of gas supply related variance account balances and unnecessarily high retroactive changes.

Board Findings

6.4.3 The Board recognizes the necessity of striking a balance between frequent ratepayer one-time debits or credits arising from the disposition of balances in the gas supply related deferral accounts, and ratepayers' tolerance of the level of adjustments that result. The Board notes the considerable negative reaction by Consumers' Gas' customers when that Company levied a one-time charge which was forecast to average $25 per typical residential customer on a weather normalized basis. In that regard the Board has concluded that, while ratepayers may not like frequent rate changes, they are even more opposed to large retroactive adjustments which result in increased gas costs.

6.4.4 The Board is prepared to accept $15 for a typical residential system gas customer, either on an accumulated basis or forecast year end balance, as the PGVA trigger for Union and the gas supply related variance accounts trigger for Centra for the 1997 test year adjustments. However, it directs the Utilities to monitor customers' reactions to the level of retroactive adjustments resulting from this Decision. Further, in order to deal with its ongoing and increasing concerns about volatility in gas costs and retroactive adjustments, the Board expects the Companies, once the $15 trigger is reached, to immediately apply for clearance of debit and credit balances in gas supply related variance accounts in order to avoid the accumulation of large balances in these accounts as have resulted over the past year.

6.5 GAS PROCUREMENT POLICIES

6.5.1 The Utilities prefiled a document entitled Gas Procurement Policies for Centra and Union Gas Supply. The Companies filed a revised version on August 30, 1997.

6.5.2 Parties to the ADR Settlement Agreement accepted the new Gas Procurement Policies, subject to the Companies' agreement to expand on the requirements relating to "financial information and assurances" and to provide particulars of "Exception to Tendering Process" to the Board's ERO.

Board Finding

6.5.3 The Board does not have any reason to reject the Utilities' Gas Procurement Policies. Subject to the Companies' agreements given in the ADR process, the Board accepts the policies for 1997.

6.6 RISK MANAGEMENT

6.6.1 In prefiled evidence, the Companies advised that the risk management programs of Union and Centra had been combined, resulting in a streamlining of the reporting of financial positions, and, in the Companies' view, making it appropriate to evaluate the program for both Companies on the basis set out by the Board for Union in its E.B.R.O. 486 Decision.

6.6.2 In the E.B.R.O. 486 Decision, the Board stressed that the extent of adherence to an approved risk management strategy would not be the sole determinant of prudence. Prudence would be judged on the basis of overall results of the risk management activities, by comparing actual results with "other indicators such as the performance of other eastern Canadian utilities, the prices available under fixed-price contracts at the time ... supply contracts were negotiated, and the price that would have resulted from total reliance on ... index prices - the 'do nothing option".

6.6.3 The Companies provided prefiled evidence on two of the three factors: risk management activities were compared with fixed price contracts contained in the portfolios for the same period, and with the "do nothing" approach. Information on the results of other LDCs' programs was, in the Companies' view, difficult to obtain and might be misleading; a high-level comparison with Consumers' Gas was provided during the hearing, but the Companies urged that no meaningful conclusions could be drawn from the comparison. The Companies did, however, agree during the hearing to obtain a third party assessment of the effectiveness of the risk management program for presentation to the Board in the next rates case.

6.6.4 According to the Companies, “all of the risk management transactions were completed at market prices, achieved the portfolio composition goals, and were within the policy and control parameters of the risk management program”, and therefore the resulting PGVA balances should be recovered from ratepayers. The relevant periods covered by the request are April 1, 1995 to December 31, 1996 for Union, and January 1, 1995 to December 31, 1996 for Centra.

6.6.5 The estimated cost per year of the operation of the Companies' risk management program was $196,600.

Positions of the Parties

6.6.6 Board Staff reviewed the results of the various comparisons, and concluded that “at present, given the limited nature of the evidence available, there is no way for the Board to adequately review the actual prudence of gas supply risk management transactions.” Board Staff argued that information is lacking as to the level of risk that system customers are willing to bear, and that the more pro-active a risk management program is, the more information the Board will need to judge its prudence.

6.6.7 In the circumstances, Board Staff submitted that an interim “mechanical” risk management strategy should be imposed, requiring the Companies to lock-in indexed gas contracts within specific upper and lower bounds. The proposed third party assessment agreed to by the Companies should, in Board Staff’s view, study the price implications of maintaining a gas portfolio with a pre-determined fixed/floating price ratio, and include historical analysis of gas purchase transactions, and information on the expectations of system gas purchasers. In the meantime, Board Staff was satisfied that the Companies followed the policies they have previously presented to the Board.

6.6.8 CAC submitted that it was unable to make any submission with respect to the prudence of the Companies’ risk management activities, noting that there appears to be a “stand-off” between the Companies and the Board as to the appropriate criteria for the determination of prudence. CAC submitted that an independent means of assessing the Companies’ performance in this area is needed, and that some sort of incentive system might encourage appropriate risk management. In this regard, it urged the Board to require the Companies to file alternatives at the next rates hearing.

6.6.9 IGUA submitted that, whatever the predetermined goals of a risk management program, the market will ultimately determine the extent of its success in meeting those goals. It argued that if the Board is satisfied with the objectives of the Companies' risk management program, and finds it has been carefully and competently administered, it would be inappropriate to disallow recovery of the costs associated with carrying out the program.

6.6.10 OCAP expressed the concern that the Companies' risk management program is speculative in nature, and represents an attempt on the part of the Companies to "outguess the market". In OCAP's view, the Companies' program should be based on "automatic rules", to protect its customers from undue risk.

6.6.11 The Companies submitted that there was no evidence that a mechanical risk management plan, such as that suggested by Board Staff, would produce better results than the present risk management strategy, nor was there evidence on how such a scheme should be implemented. In addition, the Companies did not accept that the study the Companies had agreed to undertake should address the implications of maintaining a pre-determined fixed/floating ratio; the study was to be an independent assessment undertaken of the present risk management plan.

6.6.12 The Companies argued that IGUA's position be accepted by the Board, as, in the Companies' view, the gas supply evidence confirms that the plan was adhered to, and that it has been competently and carefully managed. As to OCAP's argument, the Companies submitted that it mischaracterizes the risk management plan as speculation, in the face of clear evidence by the Companies' witnesses to the contrary.

Board Findings

6.6.13 The Board finds that there is no evidence to indicate that the Companies have not adhered to the objectives of their risk management plan, and therefore it approves the costs associated with the program and the clearance of the associated balances in the PGVA deferral accounts, details of which are set out in Chapter 8. The Board acknowledges the Utilities' agreement to obtain a third party assessment of the effectiveness of the risk management program for presentation to the Board in the next main rates case. The Board also directs the Utilities to present a proposal for a mechanical risk management strategy which could be used as a comparative benchmark.

6.6.14 The Board, earlier in this Chapter, expressed concern about frequent rate changes arising from the volatility in gas costs. The Board offers the following suggestions for consideration:

> In order to reduce volatility, several alternatives are worthy of consideration, including using financial instruments to fully hedge any index-based contract volumes, to a mechanical risk management strategy subject to tight tolerances on the initiation of risk management activities, to negotiating contracts which lock in the value of the index at the time of contracting where either party could then use financial instruments if it sought a price which would reflect market changes for a portion of its contract volumes.

6.7 TRANSPORTATION PLANS

6.7.1 The Utilities filed a summary of their transportation contracts. Union indicated it had requested 1,416 10^3m^3/d of new TCPL FT long-term service commencing November 1, 1997. In addition, it was the Utilities' evidence that TCPL had included 235 10^3m^3/d to Centra's Sault Ste. Marie delivery area and 95 10^3m^3/d to Centra's Eastern delivery area in its 1997 transportation service forecasts.

6.7.2 In E.B.R.O. 486 the Board directed Union to address why the Company had not attempted to obtain a reduction in its toll charges from its affiliate, St. Clair Pipeline (1966) Ltd. ("SCPL"). In its supplemental evidence Union reported that it intended to "pursue a complaint respecting the SCPL tolls effective July 1, 1996".

6.7.3 Union also filed supplemental evidence on its new Limited Balancing Agreements with TCPL which will provide that any shortfalls in TCPL's Storage and Transportation ("STS") customers' shipments, within certain tolerances, will not attract variance charges.

6.7.4 Subject to a review of the Utilities' Interruptible Rates and Policies, the parties to the ADR Settlement Agreement accepted the Companies' evidence on their transportation service plans.

Board Finding

6.7.5 Subject to the Board's Findings on Centra's queuing policies for firm service found under its discussion of Rates 16 and 25 in Centra's Cost Allocation and Rate Design Chapter, and Union's proposed displacement policy found in the Direct Purchase Chapter, the Board accepts the Utilities' transportation plans for 1997.

6.8 UNION'S GAS SUPPLY PORTFOLIO

6.8.1 Parties to the ADR Settlement Agreement, other than Board Staff, accepted Union's evidence on its gas supply portfolio (firm and spot purchases) for 1997. Board Staff reserved the right to cross-examine on the treatment of Ontario production and the increase in storage volumes.

6.8.2 Union adjusted the forecast volumes in its November 1996 revised forecast cost of gas to reflect adjustments resulting from the ADR Settlement Agreement. The E.B.R.O. 494-01 and 494-02 Interim Rate Orders were based on those volumes.

6.8.3 From the date of the original filing in May 1996 to the filing of the January 27, 1997 Notice of Motion, Union increased its forecast cost of all its gas supplies from \$93.653 10^3m^3 to \$118.009 10^3m^3 representing a 26% increase.

6.8.4 In its January 27, 1997 Notice of Motion Union forecast the Alberta border firm cost as follows:

- long-term firm supplies: \$66.259 10^3m^3 or \$1.747/GJ;
- short-term firm supplies: \$67.853 10^3m^3 or \$1.789/GJ; and
- total firm supplies: \$66.729 10^3m^3 or \$1.760/GJ.

6.8.5 On February 17, 1997 the Board issued its E.B.R.O. 494-02 Interim Rate Order in which it approved, on an interim basis effective March 1, 1997, rates based on Union's January 1997 12-month forward forecast cost of gas.

6.8.6 Union's evidence showed that, from 1993 to 1997, the volumes of gas that it was purchasing from local producers fell from 161,980 10^3m^3 to 32,342 10^3m^3. Union's witness testified that a number of long-term local producer contracts had expired and that Union had been unsuccessful in negotiating a price with the local producers.

6.8.7 Board Staff was initially concerned that the reduction in local production volumes might reduce supply flexibility and increase the need for storage. However, Board Staff was ultimately satisfied that Union could not purchase local production at prices that would lower the overall cost of Union's portfolio of gas supplies.

Board Finding

6.8.8 The Board confirms Unions's January 1997 forecast cost of gas and gas supply volumes as approved in the E.B.R.O. 494-02 Interim Rate Order.

Union's Storage Forecast

6.8.9 Union forecast a total peak storage capacity for 1997 of 3,516.7 10^6m^3. Of this capacity 1,959.6 10^6m^3 was required for in-franchise service and the balance contracted to C1 storage customers. The 1997 gas supply plan forecast an opening inventory balance of 1,529 10^6m^3 for in-franchise service and a closing balance of 1,233 10^6m^3. In addition the forecast volume stored for others was 1,781 10^6m^3.

6.8.10 Except for Kitchener the parties to the ADR Settlement Agreement accepted Union's in-franchise storage forecast. Kitchener reserved the right to cross-examine and argue that Union should make a greater allowance for contingencies, but in the end did not take issue with Union's forecast.

6.8.11 Board Staff initially queried Union's forecast increase in overall storage volumes but was ultimately satisfied that the forecast was reasonable.

Board Finding

6.8.12 The Board is satisfied on the evidence that Union's in-franchise storage forecast for 1997 is reasonable.

Union's Unaccounted for Gas

6.8.13 In E.B.R.O. 486 the Board approved Union's 1995 forecast of Unaccounted for Gas ("UFG") of 55,325 10^3m^3 based on a three year weighted rolling average. For 1997 Union forecast UFG at 80,328 10^3m^3 reflecting a calendar year three year weighted average of actual UFG volumes. This increase is due to a 1995 actual of 110,965 10^3m^3.

6.8.14 Parties to the ADR Settlement Agreement accepted Union's evidence on UFG and Union agreed to examine alternate methodologies to allocate UFG separately for storage, Dawn-Trafalgar System transmission, other transmission and distribution and to file the results in the 1998 rates case. Parties to the ADR Settlement Agreement agreed that Union should be permitted to establish a deferral account to record the costs of this examination, subject to the usual review of the costs incurred.

6.8.15 Union's Supplemental Evidence showed that for the latest year in which data was available, 1995, Union's unaccounted for gas represented 0.40% of the gas received into its system. In comparison, for the same year, Consumers' Gas' UFG represented 0.78% of its total volumes. The American Gas Association reported that, for 1994, an average industry level for unaccounted for gas was 1.6% of total inputs.

Board Findings

6.8.16 The Board accepts the ADR Settlement Agreement on Union's forecast level of UFG for 1997.

6.8.17 The Board recognizes that Union may eventually separate its distribution, transportation and storage operations into separate regulated business units. The Board therefore accepts Union's agreement to examine methods to allocate UFG separately for storage, the Dawn-Trafalgar System and other transmission and distribution activities. In the Chapter entitled Deferral and Variance Accounts, the Board has approved the establishment of a deferral account to record Union's costs of examining methods of allocating UFG among its Dawn-Trafalgar system, other transmission lines, storage and distribution.

Union: TransCanada Gas Services Arbitration

6.8.18 Union has a long-term gas supply contract with TCGS, an affiliate of TCPL. The price renegotiation provisions under this contract allow for third party arbitration using the services of the Vancouver Centre for Commercial Disputes.

6.8.19 Union’s evidence was that it did not seek an arbitration and that in September 1995, it had reached agreement with TCGS on a new price for the period November 1995 to October 1996. However this price was rejected by the TCGS producers upon a ballot. Union stated that the main reason for rejection was the fact that producers wanted to be properly compensated for providing gas under TCPL's firm service tendered ("FST") contracts and the upstream differential paid at that time was felt to be too low.

6.8.20 TCGS filed for arbitration on October 13, 1995, while negotiations continued. Agreement was reached on FST, but in the interim, the NYMEX forward index had risen to US$3.50/mmbtu and Union refused to accept the NYMEX indexation at that point in time.

6.8.21 The Arbitration proceeding commenced on April 22, 1996 and focussed on the issues of indexed vs fixed price and, if a fixed price was to be determined, whether it would be based only on information known to the parties at the time of contract renegotiation in October 1995, or on updated recent market information.

6.8.22 Union proposed a fixed price of $1.31/GJ. TCGS proposed an indexed price with a base of $2.064/GJ on November 1, 1995. After a lengthy proceeding, the Arbitrators awarded a fixed price of $1.61/GJ, considerably less than the price of $1.977/GJ which had been rejected by the producers. Union stated that the Arbitration had, in return for arbitration costs of $920,000, including legal costs of $585,000, saved its customers approximately $5 million compared to accepting the price roll over provision in the contract with TCGS.

6.8.23 In its E.B.R.O. 486-03 Decision, the Board directed Union to apply for an accounting order in respect of the TCGS Arbitration costs, once the costs were known with greater certainty. In February 1996 Union made application and was authorized to set up deferral account No. 179-94, through an Accounting Order UA 105 issued by the Board, in order to capture the costs associated with the TCGS Arbitration.

6.8.24 The parties to the ADR Settlement Agreement failed to reach agreement on the quantum of arbitration costs to be recovered in 1997 and, in particular, some parties disputed the amount of $585,000 for legal costs. Union subsequently filed a transcript undertaking which provided more details on the legal costs.

Positions of the Parties

6.8.25 Union submitted that it did not seek an arbitration, that it had no choice but to participate, and that the costs, although high, were more than offset by the savings.

6.8.26 CAC submitted that, where a utility wishes to recover professional fees in rates, it should supply the same kind of information that intervenors are required to file in support of cost claims. In addition, the Companies should be required to supply the following information:

- description of issues covered in the proceeding;
- narrative explanation of the hours spent;
- other explanation necessary to support the hours spent; and
- reference to comparable cost claims and awards.

6.8.27 CAC submitted that the Board, from its experience in assessing cost awards, can impose accepted standards of reasonableness on the claim for outside legal fees. CAC proposed that the Board allow a total of 1,500 hours comprised of:

- 140 hours for attendance at the hearing;
- 236 hours for argument; and

- 1,124 hours for preparation.

6.8.28 CAC submitted that by using this formula, outside Counsel would still be granted a preparation to attendance ratio of 8:1 and the allowable claim for legal costs would be reduced to $339,000 based on an hourly rate of $226.

6.8.29 Noting that CAC had taken the lead on this issue, IGUA adopted the submissions of CAC.

6.8.30 Board Staff submitted that the Board should not penalize Union for trying to get the best price for its system customer. However it suggested that this concern must be tempered by the fact that under the current regulatory construct, there is little incentive to keep arbitration costs low. In Board Staff's submission, the amount approved should be the Company's original estimate of $638,000 plus a variance of 25%. Board Staff admitted that 25% is arbitrary, but that is a fair adjustment to a forecast cost of service item. Board Staff submitted that Union should be allowed to recover only $800,000 of the requested cost recovery of $920,000.

6.8.31 Union, in reply, submitted that the evidence the Company had provided on this subject was both extensive and complete.

6.8.32 In the Company's submission the details it had provided met the information requirements which CAC had submitted were necessary to justify the recovery of the arbitration costs, with the sole exception of information on the costs incurred by TCGS, which were not available to Union.

6.8.33 Union submitted that the evidence is clear that the issues dealt with in the arbitration became numerous and were complex, principally because of TCGS' approach, and it was unrealistic to, as Board Staff had argued, rely on the original projection of costs made at the time the deferral account was requested.

6.8.34 In Union's view, it has supplied all the information necessary to support the $920,000 of costs incurred in the arbitration and accordingly, there is no reason for the Board to find other than for full recovery.

Board Findings

6.8.35 The Board finds that Union has filed in evidence all the information required to document how the $920,000 in arbitration costs were incurred. The Board notes that none of the parties challenging either the total cost of $920,000 or the legal cost component of $585,000, have suggested that the costs were imprudently incurred, rather they questioned whether the quantum was higher than estimated and whether the time docket for outside Counsel demonstrated a reasonable balance between preparation and hearing attendance, such as is typically experienced in the Board's own proceedings.

6.8.36 The Board accepts the Company's position that the costs of the Arbitration were difficult to estimate and finds no reason to reduce the amount to be recovered on this ground.

6.8.37 While the Board finds merit in the suggestion of CAC that it is appropriate to apply the same judgement used in assessing the legal cost components of cost award claims in proceedings under the Act, to costs of outside Counsel retained by the Companies in proceedings such as arbitration, the Board finds that it has no evidence to suggest that the same guidelines would apply to the type of arbitration proceeding in question. Therefore the Board approves the recovery of the $920,000 in TCGS Arbitration Costs.

6.9 CENTRA'S GAS SUPPLY PORTFOLIO

6.9.1 Centra initially forecast its firm WACOG and buy/sell reference price for 1997 would be $1.463/GJ or $55.35 10^3m^3 at the Alberta border.

6.9.2 On August 30, 1996 Centra revised this forecast for 1997 to $1.45/GJ or $54.767/$10^3m^3$ at the Alberta border.

6.9.3 On November 8, 1996 Centra filed a Notice of Motion requesting interim rates to reflect certain forecast increases including a forecast increase in its cost of gas. Centra did not request an increase in its firm WACOG in the Notice of Motion since that request was being addressed through the QRAM.

6.9.4 On November 27, 1996, in an oral Decision, the Board approved an interim increase in Centra's rates to reflect the Company's forecast increase in gas supply costs. The Board also stated that it would be appropriate to incorporate any uncontested adjustments resulting from Centra's proposed QRAM.

6.9.5 On December 2, 1996, the Board received an Application from Centra pursuant to its QRAM requesting that the Board approve $1.48/GJ as its firm WACOG and buy/sell reference price.

6.9.6 Cibola was the only party that questioned Centra's forecast firm WACOG. Its letter was received on December 11, 1996, beyond the date for response. The Board has dealt with Cibola's concerns in its comments on the QRAM in the February 17, 1997 Interim Rate Orders and in this Decision.

6.9.7 On December 24, 1996 the Board issued its E.B.R.O. 493-01 Interim Rate Order which reflected the Board's Decision on Centra's November 8, 1996 Motion and Centra's quarterly rate adjustment Application.

6.9.8 On January 31, 1997 Centra applied once again for a "quarterly" rate adjustment to be implemented two months into the quarter, March 1, 1997, to reflect a twelve month forecast of firm WACOG and buy/sell reference price of $64.64 10^3m^3 or $1.71/GJ. Centra acknowledged that it was requesting a quarterly rate adjustment one month in advance of the normal implementation date for such an adjustment in order to address on a timely basis the rate impact that will result from delaying a change in gas prices. On February 17, 1997 the Board issued its E.B.R.O. 493-02 Interim Rate Order in which it approved rates based on Centra's January 1997 forecast firm WACOG.

Board Finding

6.9.9 The Board confirms Centra's forecast cost of gas as reflected in the E.B.R.O. 493-02 Interim Rate Order for the purpose of setting rates for the 1997 test year, subject to any future adjustments as a result of Board approval of any further application to change rates to reflect changes in the forecast cost of gas.

Centra's Storage Plans

6.9.10 Centra initially forecast its total storage costs for 1997 at $9,847,100 subsequently updated in November to $14,454,000 and the cost of short-term storage in 1996 (in) and 1997 (out) at $\$28.663/10^3m^3$ and $\$22.0/10^3m^3$ respectively.

Board Finding

6.9.11 Parties to the ADR Settlement Agreement accepted Centra's storage plans and after reviewing the evidence the Board approves Centra's forecast of storage volumes, costs and revenues for the purpose of determining 1997 rates.

6.10 SUMMARY OF 1997 FORECAST GAS COSTS

6.10.1 Based on the Utilities' March 3, 1997 filing in responses to the Board's E.B.R.O. 493-02/494-02 Interim Rate Orders the Board finds that the cost of gas to be reflected in Union's and Centra's Costs of Service for the 1997 test year is $591,642,000 and $342,139,000 respectively.

7. CAPITAL STRUCTURE AND COST OF CAPITAL

7.0.1 The Companies, OCAP and Board Staff retained experts to prepare forecasts of short and long-term interest rates, financial market conditions and to make recommendations regarding the appropriate capital structure and cost of capital for both Union and Centra for the 1997 test year. This evidence was reviewed in the ADR process and a recommended capital structure and cost of capital was agreed to as part of the ADR Settlement Agreement. Subsequently during the hearing the Board requested the parties to update their interest rate and other forecasts that underpinned their original evidence upon which the ADR Settlement Agreement on cost of capital was based.

7.1 FINANCIAL FORECASTS

7.1.1 The original and updated forecasts of the various experts retained by the parties are shown in Table 7.1:

Table 7.1: Financial Forecasts of Companies' and Intervenors' Experts

	Original Experts' Forecasts Prefiled Evidence			**Updated Forecasts Requested by Board**		
	Union Centra	**Board Staff**	**OCAP**	**Union Centra**	**Board Staff**	**OCAP**
Short Term Rates 90/91 T-Bills (%)	5.25-5.50	4.60-5.45	n/a	4.00-4.50	3.30-3.50	n/a
Long Term Rates 30 year Canadas (%)	7.50-8.0	7.85-8.15	7.50-8.0	7.00-7.50	6.78-7.00	7.25-7.75
Consensus Report	90-Day T-Bills: 5.50% Long Canadas: 8.25%			90-Day T-Bills: 3.60% Long Canadas: 7.15%		

7.2 UNION: CHANGE FROM NORMALIZED (DEFERRED) TO FLOW-THROUGH INCOME TAX ACCOUNTING

7.2.1 In prior years Union's income taxes were calculated on the basis of normalized (deferred) tax accounting.

7.2.2 In the E.B.R.O. 486 Decision, the Board noted that Union was one of the few utilities in Canada that used deferred tax accounting. It also expressed the view that waiting for a possible merger of Union and Centra could delay the resolution of the issue; and that any change should only impact Union's customers and not Centra's. In that Decision the Board directed Union to provide evidence in its next main rates case both on a normalized (deferred) and flow-through tax basis and to provide a proposal as to how already collected deferred taxes would be treated under a flow-through option.

7.2.3 Union accordingly filed the requested evidence and proposed changing from normalized to flow-through tax accounting starting in the test year.

7.2.4 The Companies' evidence was that the determination of taxable income requires that book depreciation be added back to earnings before tax and capital cost allowances ("CCA") are deducted. Book depreciation and tax depreciation are recognized at different rates and there is a timing difference.

7.2.5 In general, the tax depreciation rate exceeds the book depreciation rate. Consequently, taxable income and taxes payable tend to be lower in the earlier years of the life of an asset such as utility plant and greater in the later years. Under flow-through tax accounting the effective tax rate is lower than the statutory tax rate in the early years of asset life and then reaches a cross over point and becomes greater.

7.2.6 Normalized tax accounting smooths out the tax-related impacts on cost of service and income by using a tax provision equivalent to the book accounting income which therefore includes a current tax portion and a deferred (future) tax provision. The deferred tax provision recognizes that tax avoided in the earlier years will have to be paid later. The deferred tax provisions over a number of years result in accumulated deferred taxes that are offset by a deferred tax liability. Following the cross over year the deferred taxes associated with an asset are drawn down as the taxes become payable.

7.2.7 For the 1997 test year Union's original forecast was that if flow-through tax accounting was adopted, income taxes payable would be reduced by about $9 million. The Company also projected that following the change to flow-through tax accounting, the Company's capital expenditure program would still generate tax deductions in excess of book depreciation.

7.2.8 The experts retained by OCAP and Board Staff accepted the proposed change from normalized to flow-through tax accounting and the parties to the ADR Settlement Agreement also supported the proposed change.

7.2.9 As noted previously in Chapter 3, the Companies originally proposed to maintain their rental programs on deferred tax accounting in anticipation of the separation of these ancillary programs from the regulated utility business in 1997. In the ADR process the Companies agreed to retain the rental programs as part of the 1997 Utility business and to use flow-through tax accounting for the test year. The rental programs added $81.4 million to Union's 1997 total capitalization as filed and $24.2 million to Centra's 1997 capitalization.

Board Findings

7.2.10 The Board's understanding of the Company's evidence is that the change to flow-through tax accounting results in no significant impact on ratepayers in the test year. The change is supported by both the Company's and intervenors' experts and the unchallenged evidence is that the change will bring Union in line with other Canadian utilities and lead to a consistent approach with Centra.

7.2.11 The Board accordingly finds the change to flow-through tax accounting for Union to be appropriate.

7.3 UNION: DEFERRED TAX DRAW DOWN AND ADJUSTMENTS TO CAPITAL STRUCTURE

7.3.1 Union stated that the main consequences of the change to flow-through tax accounting are:

! the need for transitional measures to deal with the existing accumulated deferred tax balance of $262.2 million related to the regulated Utility, exclusive of the rental program as of the end of 1996; and

C adjustments to the utility capital structure in order to maintain financial ratios at acceptable levels.

7.3.2 Based on the recommendations of its experts, Union proposed to draw down the deferred tax pool associated with its accumulated capital asset base using the natural draw down method. As taxes resulting from depreciation of the assets become payable, tax is drawn down from the deferred tax pool. Union's experts indicated that natural draw down would ensure the maintenance of appropriate interest coverage ratios and cash flow in future years.

7.3.3 Union proposed that the deferred tax balance be "frozen" at the end of 1996 and the balance reduced over 17 years as the accumulated income taxes otherwise become payable. According to Union's calculations, as filed in evidence, the use of the 'natural draw down' method would mean no draw down in 1997, since CCA income tax deductions exceed accounting deductions (depreciation) until a cross over occurs and draw down commences in 1998. The draw down of deferred taxes is forecast to reduce the annual revenue requirement from 1998 until the year 2013.

7.3.4 In future years, as the rate base increases and as the deferred tax balance is reduced there is a need to attribute more debt and equity to the utility capital structure. According to Union, the natural draw down method ensures that the decline in the deferred tax balance matches the depreciation of the assets associated with that balance and has the least impact on financial coverage ratios.

7.3.5 Union stated that it had examined other alternatives to the natural draw down method including a 10-year straight line draw down, but its calculations showed that interest coverage would decline by an average 0.22 times in the period 1997-2001. The 'natural draw down' method proposed by Union provides benefits to ratepayers without significantly eroding interest coverage ratios.

7.3.6 OCAP's experts, in supporting the natural draw down method proposed by the Companies, characterized the methodology as tantamount to maintaining normalized tax treatment for existing assets. Benefits to ratepayers result from the ratepayers having already paid taxes under normalized (deferred) tax treatment and nothing would change as a result of the switch to flow-through accounting on a prospective basis.

7.3.7 In the ADR Settlement Agreement Union acknowledged that there may be issues of intergenerational equity and fairness related to the disposal of the deferred tax balance and undertook to file evidence on a proposed allocation methodology and also to address intergenerational equity and fairness in the 1998 rates case.

Board Findings

7.3.8 The Board finds that Union's proposal to use the natural draw down method to be the most practical alternative presented to it. However. the Board is concerned that Union has not thought through the necessary accounting and audit trail for the draw down of the estimated $262 million in deferred taxes over the period 1998 to 2013. The Board directs Union to establish the necessary accounting and audit system to ensure the deferred tax draw down and its allocation into rates is tracked and reported in future rates cases.

7.3.9 The Board also directs the Company to ensure in its cost allocation and rate design following the proposed amalgamation of Union and Centra that the benefits and costs flow, to the extent possible, only to those customers who contributed to the accumulated deferred tax pool. The Board understands these to be the in-franchise and ex-franchise customers for S&T Assets and Union's in-franchise customers or the equivalent successor customer grouping for Distribution Assets.

7.4 UNION: CAPITAL STRUCTURE AND COST OF DEBT

Capital Structure

7.4.1 The Company proposed an increase in the deemed utility common equity component from 29.0% to 35.0%, based on its experts' and management's view that following the change to flow-through taxes, 35.0% is compatible with Union's business risks, comparable to equity ratios maintained by other gas distributors and necessary to maintain coverage ratios and financing flexibility. Union's original proposal included separation of the rental program with a deemed capital structure of 29.0%, thus resulting in an average utility capital structure of 34.5% for 1997.

7.4.2 Another significant change to Union's capital structure resulted from management's decision to replace $125 million of preference shares with a combination of short-term debt and common equity. This move was prompted by a change in the Canadian Institute of Chartered Accountants ("CICA's") tax accounting treatment which treats most preference share dividends as interest expense and thus would negatively impact Union's interest coverage ratio. Union indicated that it would be able to redeem all but $10.5 million of its outstanding preference shares without penalty.

7.4.3 The Company's evidence was that these two changes resulted in a required equity injection of $116.0 million in 1997. Forecast growth in the rate base would add a further $30 million equity requirement for a total forecast equity increase of $147 million over the Board approved level for the 1995 test year.

7.4.4 In the ADR Settlement Agreement the parties agreed to retain the rental program in the utility capital structure for the test year and to a deemed utility equity component of 34.0%.

Union: Cost of Short and Long-Term Debt

7.4.5 Union's *short-term debt cost* is calculated based on the forecast requirement times a blended cost rate. This blended rate is calculated based on bank loans at forecast prime (6% weight) and the forecast 90 day T-Bill rate plus spread and cost (94% weight). Union's updated evidence forecast $58.676 million of short-tern debt at a blended rate of 6.42% resulting in an annual cost of $3.767 million. The ADR Settlement Agreement resulted in short-term debt increasing, primarily as a result of the recommendation to retain the rental equipment program in Rate Base for 1997, to a recommended amount of $121.718 million of short-term debt at a blended rate of 5.45% and 1997 test year cost of $6.634 million.

7.4.6 Union does not plan any *long-term debt* issues in 1997, so the proposed long and medium term debt for the test year is the embedded $1,241.605 million in outstanding debt at an actual average rate of 10.19% and test year cost of $126.520 million.

7.5 CENTRA: CAPITAL STRUCTURE AND COST OF DEBT

Capital Structure

7.5.1 No major changes to Centra's capital structure or common equity ratio of 36.0% were proposed for 1997. Significant growth in the Rate Base from $669 million to $772.5 million between 1995 to 1997 required an injection of $115 million in long-term debt and increase in equity. As a result of the ADR Settlement Agreement to retain the rental program within the Utility the proposed average test year Rate Base increased to $792.1 million with a corresponding increase in unfunded short-term debt from $15.077 million to $27.601 million.

Centra: Cost of Short and Long-Term Debt

7.5.2 Centra's *short-term debt cost* is calculated based on the forecast requirement using the forecast 90/91 day T-Bill rate plus a 75 basis point stamping fee. Centra's updated forecast was for an average $15.077 million of short-term debt at a rate of 6.75% resulting in an annual cost of $1.018 million. The ADR Settlement Agreement resulted in a recommended short-term debt amount of $27.601 million at a rate of 5.75% and a 1997 test year cost of $1.587 million.

7.5.3 Centra's prefiled evidence indicated a forecast test year average *long-term debt* of $470.583 million. Two new debt issues were planned - $65 million in 1996 at a forecast coupon rate of 8.64% and a further $50 million at a forecast rate, including issue costs, of 8.90% in 1997. The ADR Settlement Agreement recommended an effective rate, including issue costs, of 8.70% for the 1997 debt issue. This resulted in an average 1997 total long-term debt of $470.583 million at an embedded cost of 9.72%.

7.5.4 In its updated evidence, Centra indicated that it had issued $75 million long-term debt in October 1996 at a coupon rate of 7.80% corresponding to an effective rate, including issue costs, of 7.96% and that it still planned to issue $50 million in 1997 at a forecast effective rate of 8.70%. The Company subsequently indicated in its reply argument that the average total long-term debt would now increase by $10 million to $480.583 million at an average (embedded and new) cost rate of 9.57%.

7.6 UNION: COST OF COMMON EQUITY

7.6.1 The experts retained by the Companies and intervenors made a variety of recommendations regarding the allowable rate of return on the proposed 34.50% equity component for the 1997 test year. Each party employed a series of tests based on its own input assumptions and based its final recommendations on different weighting of test results. The results are set out in Table 7.2.

Table 7.2: Union: Proposed Return on Common Equity (Original Filings)

Party	**Comparable Earnings Test**	**Risk Premium Test**	**DCF Test**	**Weighted Return on Equity**
Union (Sherwin/McShane)	11.75-12.5%	12.25-12.5%	12.3-12.7%	12.25-12.5%
Board Staff (Cannon)	10.77-10.92%	10.1-10.7%	9.4-10.7%	10.5-10.9%
OCAP (Booth/Berkowitz)	n/a	9.82-10.40%	8.96-9.86%	10.25%

7.6.2 Union later updated its return on equity evidence and proposed a return on common equity of 12.75% for the 1997 test year.

7.7 CENTRA: COST OF COMMON EQUITY

7.7.1 Centra initially filed evidence in support of a 12.75% return on common equity for the 1997 test year.

7.7.2 The parties' experts used the same financial market data and tests, plus a judgement of the relative "risk" of the two Companies, to prepare their recommendations for Centra's allowable rate of return on its 36% equity component for the 1997 test year. The results are set out in Table 7.3.

Table 7.3: Centra: Proposed Return on Common Equity (Original Filing)

Party	Proposed Return on Common Equity
Centra (Sherwin, McShane)	12.75%
Board Staff (Cannon)	11.15%
OCAP (Booth, Berkowitz)	10.25%

7.7.3 Centra later updated its return on equity evidence and proposed a return on common equity of 13.0% for the 1997 test year.

7.8 ADR SETTLEMENT AGREEMENT

7.8.1 The following parties reached a consensus on the various components of the Companies' Capital Structures and Costs of Capital for the 1997 test year: Union, Centra, Kitchener, Schools, Terra, NOVA, ONA, Board Staff, CAC, CENGAS, CIPEC, Direct Energy, ECNG, NRG, IGUA, OCAP. GEC and Pollution Probe reserved the right to argue that Union and Centra's return on common equity should be reduced to reflect, in their view, failure of the Companies to comply fully with the Board's directive regarding DSM Programs.

7.8.2 The Companies' original proposals and the ADR Settlement Agreement recommendations are set out in Table 7.4 below:

Table 7.4: Companies' Capital Structure and Cost of Capital per ADR Settlement Agreement

Union and Centra 1997 Capital Structure and Cost of Capital as filed and per ADR Settlement Agreement								
Particulars ($000)	**Union**				**Centra**			
AS FILED (Update)	**Capital Structure $**	**%**	**Cost Rate %**	**Requested Return $**	**Capital Structure $**	**%**	**Cost Rate %**	**Requested Return $**
Long Term Debt	1,241,605	58.16	10.19	126,520	470,583	60.92	9.75	45,860
Unfunded Short Term Debt	58,677	2.75	6.42	3,767	15,077	1.95	6.75	1,018
Preference Shares	98,046	4.59	6.88	6,746	8,766	1.13	7.09	622
Common Equity	736,524	34.50	12.75	93,907	278,114	36.00	13.00	36,155
Utility Rate Base	*2,134,582*	*100.0*	*10.82*	*230,940*	*772,540*	*100.0*	*10.83*	*83,654*
PER ADR	**Capital Structure $**	**%**	**Cost Rate %**	**Requested Return $**	**Capital Structure $**	**%**	**Cost Rate %**	**Requested Return $**
Long Term Debt	1,241,605	56.07	10.19	126,520	470,583	59.41	9.72	45,741
Unfunded Short Term Debt	121,718	5.50	5.45	6,634	27,601	3.48	5.75	1,587
Preference Shares	98,046	4.43	6.88	6,746	8,766	1.11	7.09	621
Common Equity	752,827	34.00	11.50	86,575	285,160	36.00	11.75	33,506
Utility Rate Base	*2,214,196*	*100.0*	*10.23*	*226,475*	*792,110*	*100.0*	*10.28*	*81,455*

7.9 RESPONSE TO BOARD REQUEST FOR SUBMISSIONS ON UPDATING THE 1997 COST OF CAPITAL

7.9.1 During the proceeding the Board requested the parties to update the forecasts that underpinned their recommended cost of short and long-term debt and common equity for the test year and to address in argument whether the cost of debt and equity recommended in the ADR Settlement Agreement should be adjusted to reflect this new information.

Positions of the Parties

7.9.2 As noted earlier in Table 7.1 the Companies updated their forecast of 90 day T-Bill rates from 5.5% to 4.5%. They also updated the prime rate forecast from 7.0% to 4.85%. The forecast rate for Long Canadas was updated from 7.5-8.0% to 7.0-7.5%.

7.9.3 The Companies submitted that the ADR Settlement Agreement was a result of a consensus reached by parties of varying interests, after very hard bargaining, at a particular point in time. The fact that interest rates have changed should not be treated as an isolated element and in the Companies' view, it would not be equitable to adjust for one element when other elements are also subject to countervailing changes.

7.9.4 The Companies also submitted that although interest rates are currently declining, that could change. They noted that when Consumers' Gas filed evidence of interest rate increases in E.B.R.O. 487 and suggested that the cost of capital should be reconsidered they were censured for doing that at the last moment. The Companies argued that the same principles should apply in this case.

7.9.5 Board Staff noted that the short-term debt rate agreed upon by the parties to the ADR Settlement Agreement was lower than the average of the evidence at that time.

7.9.6 Based on the updates by Board Staff's experts, Union's *short-term debt rate* would be calculated as 3.85%. The corresponding after tax reduction to the 1997 revenue requirement would be about $1,351,000.

7.9.7 Board Staff recalculated Centra's *short-term debt* rate at 4.18%, resulting in a decrease in the 1997 after tax rate revenue requirement of approximately $339,000.

7.9.8 Board Staff noted that Centra had already issued $75 million of *long-term debt* at a rate of 7.96%, which would reduce the test year after tax revenue requirement by $320,000. To estimate the effect of reduced interest rate forecasts on the planned 1997 debt issue, Board Staff recalculated Centra's *long-term debt* rate at 7.14%. This represented a reduction of 83 basis points which, when "applied to" an average amount in the cost of service of $22.917 million in 1997, would reduce the test year after tax revenue requirement by about a further $273,000.

7.9.9 Board Staff submitted that the Board in considering the public interest, should seek answers to the following questions:

- is the change supported by evidence which is reliable and tested?
- does any change supported by the evidence represent a significant amount?
- is a change fair to all parties?

7.9.10 Board Staff took no position on the cost of *short and long-term debt* for the test year, but suggested that if the Board decided that actual interest rates warranted a change in the cost rate at the time of the Board's Decision, such changes could be prorated into the cost of service prospectively.

7.9.11 Board Staff noted that although estimates of the *cost of common equity* rely in part on long-term interest rates as an input, no new evidence had been provided on the test year cost of common equity capital subsequent to the ADR Settlement Agreement.

7.9.12 IGUA submitted that the issue for the Board to decide was not whether the provisions of the ADR Settlement Agreement would be different if negotiated today, but rather, whether the circumstances were such that the Board ought to refrain from accepting the provisions of the Agreement as reasonable for the purposes of deriving the test year rates for Union and Centra.

7.9.13 IGUA cited the circumstances in E.B.R.O. 487 in which it vigorously opposed Consumers' Gas' “veiled attempt to resile from an ADR Agreement”, and noted that the Board was also critical of Consumers’ Gas in that case.

7.9.14 IGUA noted that the Board in its E.B.R.O. 487 Decision recognized that although significant changes in circumstances could arise that could cause a party to depart from an agreed ADR position, the integrity of the ADR process could be undermined and so there should be a very heavy onus on a party to justify a reversal of position on a negotiated issue.

7.9.15 IGUA submitted that, in the current proceeding, none of the parties who actively participated in the negotiation of the cost of capital features of the ADR Settlement Agreement can meet the onus described by the Board in its E.B.R.O. 487 Decision.

7.9.16 IGUA urged the Board to accept the provisions of the ADR Settlement Agreement for the purposes of the test year cost of capital with the exception that the cost of the 1996 debenture issue, which is now known, should be reflected in the test year cost of service.

7.9.17 CAC submitted that the Board should not use updated information when establishing the test year cost of short and long-term debt for the Companies because:

- using updated information would undermine the ADR process and Settlement Agreement;
- if a change were made in one aspect of the Agreement, all of the other aspects should, in fairness, be open to review and change; and
- it is not clear that interest rates will continue to decline.

7.9.18 OCAP updated the evidence of its experts as noted in Table 7.1 and suggested that if the Board were inclined to change the cost rates for short and long-term debt, this could be an opportune time to revisit the use of deferral accounts to adjust for the accuracy of forecasts.

7.9.19 OCAP advised the adoption of the ADR Settlement Agreement with respect to the cost of capital issues.

7.9.20 Pollution Probe noted that it had reserved the right to argue that the Companies' allowed returns on equity should be lowered due to their failure to fully comply with the Board's directives and/or past ADR settlement agreements with respect to DSM and/or third party financing.

7.9.21 Pollution Probe submitted that the Board should set Union’s return on equity at less than 11.50% as a result of the Union's failure to develop aggressive DSM programs and that the Board should set Centra’s return on equity at less than 11.75% as a result of Centra’s failure to develop aggressive DSM programs and failure to comply with its E.B.R.O. 483/484 commitment with respect to third party financing.

7.9.22 GEC, which had also reserved its right to argue that the test year return on equity should be adjusted to reflect the adequacy of the Companies' compliance with DSM directives, indicated that it sought no such adjustment at this point.

7.10 BOARD FINDINGS ON COST OF CAPITAL

Capital Structure

7.10.1 The Board finds Union's capital structure, which recognizes changes in preference share capital, tax accounting and includes a 34.00% common equity component as recommended by the ADR Settlement Agreement, to be appropriate for the 1997 test year. Should the LGIC approve the Companies' merger application, the Board expects Union and Centra to fully justify from first principles, in the 1998 rates case, the proposed capital structure of the amalgamated Companies.

7.10.2 The Board's adjustment to Centra's recommended 1997 Rate Base and Centra's issuance of an additional $10 million in long-term debt result in reductions in Utility capitalization from the levels set in the ADR Settlement Agreement, of $2.183 million in common equity, and $13.880 million in short-term debt.

Updated Financial Forecasts and Cost of Capital

7.10.3 The Board in this proceeding accepted the ADR Settlement Agreement on the cost of capital as a reasonable evidentiary basis at the point in time when the ADR Settlement Agreement was prepared for it to make its own determination of the 1997 test year allowable cost of debt and equity.

7.10.4 Subsequent events changed the evidentiary base upon which the parties to the ADR Settlement Agreement relied.

7.10.5 The Board notes that in its E.B.R.O. 487 Decision, although it declined to change Consumers' Gas' cost of capital subsequent to the ADR Settlement Agreement, the Board stated that: "*With regard to the matter of economic forecasts we would also make it clear that we would expect that should economic conditions or financial markets change significantly from the time these (ADR) agreements were reached* *that there will be updates offered by the Applicant to recognize and address those issues; that is, if the changes occur before the end of the evidentiary phase of this proceeding."* (para 5.1.1)

7.10.6 In order to set just and reasonable rates for a prospective test year the Board will continue to take into account any subsequent events, such as significant changes in financial market forecasts for the test year, which occur after the ADR Settlement Agreement. The Board expects the Applicants and/or intervenors as a matter of course to either confirm or update their financial forecasts before the close of the evidentiary phase of the proceeding, with a view to making submissions on whether, and to what degree, the costs of capital recommended in the ADR Settlement Agreement should be adjusted by the Board to reflect the latest evidence.

7.10.7 The Board is concerned that in this aspect of this hearing, the ADR process made it difficult for the Board to base its findings on a very important issue on the best and most reasonable information. The Board respects the outcome of the ADR Settlement process in large part because it is confident that the mix of interests represented in it ensure that the public interest is protected. Where, as in this instance, the Board is urged by all parties to the process, including those representing customer interests, not to change the outcome of the process even when it appears that the public interest may require it, the Board must be concerned about the process. The Board was given little assistance by the parties in determining whether and how it should alter an outcome of the process which clearly depended upon financial market conditions which subsequently changed. In this circumstance the Board is of the view that it has no choice, if it is truly to act in the public interest, but to make its own determination of a reasonable result.

7.10.8 In making its findings on the cost of short-term and long-term debt and the appropriate return on common equity the Board has examined the latest publicly available forecasts of interest rates and satisfied itself that the updated forecasts filed at the end of the hearing are appropriate to use for the 1997 test year. These updates indicate that forecast short-term rates (90-day T-Bills) for 1997 have dropped by at least 100 basis points and forecast long-term rates (Long Canada 30-year Bonds) have dropped by 50-100 basis points from the forecast rates underpinning the ADR Settlement Agreement.

Union and Centra: Cost of Short-Term Debt

7.10.9 The Board finds that the updated evidence provided by the parties on short-term interest rates as filed in their argument is indicative of a significant and material change in the forecasts that the parties to the ADR Settlement Agreement used in their discussions on this issue.

7.10.10 The Board finds that it has an obligation to both the Companies and their ratepayers to take into account the latest updates when setting the allowed cost of components of the test year capital structure.

7.10.11 Accordingly the Board will deem a cost of short-term debt for Union and Centra that reflects the updated forecasts of short-term interest rates for 1997 which themselves reflect a 100 basis points reduction from the forecast underpinning the ADR Settlement Agreement.

7.10.12 The Board therefore finds that the allowed cost of short-term debt for the 1997 test year will be 4.45% for Union and 4.75% for Centra. The corresponding effect on the 1997 requested return is a reduction of $1,218,000 for Union and $137,000 for Centra after adjustments to the short-term debt component.

Centra: Cost of Long-Term Debt

7.10.13 The Board finds it appropriate to adjust the allowed cost of Centra's *long-term debt* to account for both the actual cost of the $75 million debt issue in October 1996 and the Companies' updated forecasts of long-term interest rates which, in the latter case, reflect a reduction of 50-100 basis points from the time of the ADR Settlement Agreement. Accordingly the Board finds that the cost of the long-term debt for the test year will reflect the actual issue cost of $75 million at an effective cost rate of 7.96% and the proposed issue of $50 million of which, according to Centra, $22.917 million will be included in the test year average capital structure, at a deemed effective cost rate of 8.0%. These adjustments will change the test year requested return by approximately $255,000 and ($160,419) respectively from the Company's original forecast.

Union and Centra: Allowed Return on Common Equity

7.10.14 The Board notes that forecast long-term interest rates, and in particular Long Canada Bond rates, are utilized in the estimation of the appropriate return on equity using the equity risk premium ("ERP") methodology. Accordingly, given the significant drop in forecast Long Canada Bond rates and the predominant reliance placed on the ERP method in this proceeding, the Board will use this evidence as a basis for making an adjustment to the Companies' allowed test year rates of return on common equity as set out in the ADR Settlement Agreement.

7.10.15 The Board has estimated implied risk premiums inherent in the returns on common equity for Union and Centra which were negotiated in the ADR Settlement Agreement, given the forecasts of Long Canada Bond rates for 1997 then in evidence.

7.10.16 The range of forecasts of Long Canada Bond yields for 1997 at that time was 7.75-8.0% which implies a risk premium of from 350-375 basis points for Union and 375-400 basis points for Centra in order to arrive at returns on common equity of 11.5% for Union and 11.75% for Centra as recommended in the ADR Settlement Agreement.

7.10.17 The Board comments that, in its view, the implied risk premiums related to the ADR Settlement Agreement for Union and Centra may be high relative to the level of risk premiums found for similar utilities in other jurisdictions which rely solely on the ERP methodology. However, the Board will use the implied risk premium resulting from the application of the ERP methodology to the recommended returns on common equity in the ADR Settlement Agreement for the purpose of determining a reasonable return on common equity for the Companies' 1997 test year.

7.10.18 The updated evidence filed at the end of the hearing is that forecast Long Canada Bond yields for 1997 will be in the range 7.0-7.5% which, combined with the implied risk premiums above, would yield a return on common equity of from 10.75-11.00% for Union and of 11.00-11.25% for Centra.

7.10.19 The Board notes that the parties did not place sole reliance on the ERP methodology and that a reasonable rate of return on common equity could also be affected by other events subsequent to the ADR Settlement Agreement, including continuation of a strong bull market and high returns for common stocks.

7.10.20 For the above reasons, notwithstanding the fact that customer representatives argued for maintaining the ADR Settlement Agreement's returns on common equity of 11.5% and 11.75%, the Board finds it to be in the public interest to adjust the reasonable returns on common equity for the 1997 test year to 11.00% for Union and 11.25% for Centra.

7.10.21 In arriving at its findings on this matter the Board has taken into account its findings on other issues in this Decision.

7.10.22 The Board has found that it must, in the public interest, take into account any significant changes in forecast financial market conditions for the test year, which occur before the close of the hearing. In this regard the Board finds it unhelpful to receive an ADR settlement agreement which produces a single number for the recommended return on common equity for each Company, in isolation of consideration of financial market volatility and with no formula with which to adjust the recommended return.

7.10.23 The Board expects that parties to future ADR settlement negotiations will take into account consideration of the Board’s concerns on adjusting the cost of capital for significant changes in financial market conditions between the time of filing of an ADR settlement agreement and the conclusion of the hearing.

Summary

7.10.24 The Board approved capital structure and cost of capital for Union's and Centra's 1997 test year, including adjustment due to its findings on Centra's 1997 Rate Base, is shown in Appendices C and G (Union and Centra respectively).

8. DEFERRAL AND VARIANCE ACCOUNTS

8.0.1 The Board has previously approved a number of deferral and variance accounts for each Utility for Calendar 1996 in order to capture certain expenses and revenues for future disposition with approval of the Board. The rationale for such accounts arises where the Utility encounters expenses or revenues that either could not be reasonably forecast at the time rates were being established, or are subject to significant variance from forecast. It would not be reasonable to expect the Utility to either absorb the added expenses, or receive the additional benefits resulting from such variances. The Board has also on occasion established such accounts for expenses related to unexpected events outside of the Utility's control, or when the Board has directed that certain expenses or revenues be amortized over a number of years, rather than be reflected within a single rate year.

8.0.2 In establishing deferral and variance accounts the Board also defines whether the balances in such accounts will bear interest, usually at the Utility's Board approved interest rate for short-term debt calculated on the monthly opening balances of the accounts, without compounding.

8.0.3 From time to time, usually at the time of its rate application, the Utility will apply to the Board for disposition of the balances in its existing deferral and variance accounts. The Board makes a determination on the prudence of the expenditures and the reasonableness of the balances in the accounts and also determines an appropriate disposition of the balances between the shareholder and the ratepayers of the Utility, and the allocation of the ratepayer portion to the various rate classes.

8.0.4 In its rate applications the Utility will seek approval from the Board for the continuation or closure of existing accounts and to establish new deferral accounts. Between rate cases, the Utility may also seek approval for the establishment of a new deferral account by way of a Board accounting order.

8.0.5 Centra and Union filed evidence on the status of their existing individual deferral and variance accounts and on their joint deferral accounts and sought disposition of the account balances for existing accounts as of the end of 1996. The Companies also sought approval to establish a number of new accounts.

8.0.6 The Companies evidence and requested approvals are addressed under the headings:

! Union: 1997 Proposed Deferral and Variance Accounts:
  Continued Accounts;
  Proposed New Accounts; and
  Discontinued Accounts;

! Disposition of Fiscal 1996 Accounts - Union:
  Account Balances; and
  Disposition Methodology;

! Centra: 1997 Proposed Deferral and Variance Accounts:
  Continued Accounts;
  Proposed New Account; and
  Discontinued Accounts;

! Disposition of Fiscal 1996 Accounts - Centra:
  Account Balances; and
  Disposition Methodology;

! Union and Centra: 1997 Joint Activity Proposed Deferral Accounts;

! Disposition of Fiscal 1996 Joint Activity Accounts; and

! Method of Recovery--Customer Impacts.

8.1 UNION: 1997 PROPOSED DEFERRAL AND VARIANCE ACCOUNTS

Continued Accounts

8.1.1 Union proposed the continuation of the following deferral accounts:

179-24 Purchased Gas Variation Account (PGVA);
179-26 Deferred Customer Credits/Rebates;
179-30 Deferral Account for Payment of Delivery Commitment Credit;
179-34 C1 and M12 Transportation Net Revenue;
179-38 Heat Value Deferral Account;
179-39 C1 and M12 Storage Net Revenue;
179-43 Generic Hearing on System Expansion Deferred Costs; and
179-44 Deferred TCGSL Gas Supply Contract Arbitration Costs.

8.1.2 The following accounts are discussed under the heading Disposition of Joint Activity Fiscal 1996 Accounts:

179-36 Centra/Union One-time Integration Costs - Net of Amortization;
179-37 Centra/Union One-time Integration Costs - Interest; and
179-40 Incremental Impact of Shared Services.

8.1.3 Except where otherwise noted, parties to the hearing either did not participate in the ADR settlement discussion of a particular deferral account, accepted the Company's proposals, or did not oppose the continuation of the following deferral accounts, for the 1997 fiscal year of the Company.

<u>Purchased Gas Variation Account (PGVA) No. 179-24</u>

8.1.4 This account records the difference between the unit cost of all gas purchased by Union and Union's approved weighted average cost of gas (WACOG) Variances in actual transportation tolls are also captured in this account. Once the actual accumulated balance or the forecast year-end balance in the PGVA exceeds a one-time charge or credit of $10 to a typical residential system gas customer, Union is required to submit a report to the Board including an application for changes in rates or reasons why an application is not appropriate.

Deferred Customer Credits/Rebates Account No. 179-26

8.1.5 This account records the amounts of any credits (debits) or rebates of less than $10 for final customer accounts, in circumstances in which the customers cannot be located.

Deferral Account for Payment of Delivery Commitment Credit (DCC) No. 179-30

8.1.6 This account records the payment of the DCC and the revenue received by charging the FST Downstream Differential associated with Bundled T-Service (Rate R1) and Unbundled T-Service. During 1996 this account also recorded an adjustment to the FST downstream differential between the E.B.R.O. 486 approved rate and the amount reflected in TCPL's tolls for FST volumes delivered to customers between May 1, 1995 and December 31, 1995.

C1 and M12 Transportation Net Revenue Deferral Account No. 179-34

8.1.7 This account records the difference between the actual and forecast net revenues derived from C1 and M12 Services. The transportation services included in this deferral account include C1 Interruptible Transportation, M12 & C1 Non LCU protected Firm Transportation, M12 Limited Firm/Interruptible Transportation, C1 Firm Short-Term Transportation, M12 Transportation Overrun, and Energy Exchanges.

Heat Value Deferral Account No. 179-38

8.1.8 This account records variations in the heating values of natural gas received and delivered for the account of firm C1 and M12 Transportation Service customers.

C1 and M12 Storage Net Revenue Deferral Account No. 179-39

8.1.9 This account records differences between the forecast and actual C1 Peak Storage, M12 Interruptible Storage Deliverability and C1 Firm Short-Term Storage Deliverability net revenues.

Generic Hearing on System Expansion Deferred Costs Account No 179-43

8.1.10 Although this account is included in Union's financial records, it records unbudgeted costs incurred by both Centra and Union to jointly participate in the Board's generic review of system expansion in Ontario under Board File No. E.B.O. 188 until the review has been completed.

Deferred TransCanada Gas Services Limited (TCGSL) Gas Supply Contract Arbitration Costs Account No. 179-44

8.1.11 This account was established effective January 1, 1996 to record the expenses incurred by Union in its arbitration proceeding with TCGSL during 1996.

Positions of the Parties

8.1.12 The parties to the ADR Settlement Agreement agreed that the Union's evidence regarding the proposed continuation of the deferral accounts as described above should be accepted, subject to the exceptions noted below and to the parties' right to review the disposition methodology for the following accounts:

179-26 Deferred Customer Credits/Rebates;
179-30 Deferral Account for Payment of Delivery Commitment Credit;
179-38 Heat Value Deferral Account; and
179-43 Generic Hearing on System Expansion Deferred Costs.

8.1.13 The parties to the ADR Settlement Agreement agreed that a revenue sharing proportion of 25% to the shareholder, 75% to ratepayers should be applied to any balance in the C1 and M12 Transportation Services Account No. 179-34 in 1997. The parties also agreed that any balance in the C1 and M12 Storage Services Account No.

179-39 in 1997 should be shared in the proportions of 10% to the shareholder, and 90% to ratepayers.

8.1.14 With respect to PGVA Account 179-24 (Table 8.2), the parties to the ADR Settlement Agreement agreed that the only items that would require further examination during these proceedings were entries related to Spot Gas, Buy/Sell Supply, and Non Compliance Penalties. The discussion of these items pertains to the disposition of Union's PGVA balance as detailed in Table 8.2, and is addressed under the heading Disposition of Fiscal 1996 Accounts - Union.

8.1.15 The was no agreement on the need to continue the TCGSL Gas Supply Contract Arbitration Costs Account No. 179-44, nor on the disposition of the account balance.

Board Findings

8.1.16 The Board accepts Union's evidence and the ADR Settlement Agreement and approves the continuation of the accounts for 1997 requested by the Company.

8.1.17 The Board has found in Chapter 9 of this Decision that it will not grant prior approval regarding the sharing of the balance in the C1 and M12 Transportation Net Revenue Deferral Account No. 179-34 and the C1 and M12 Storage Net Revenue Deferral Account No. 179-39.

8.1.18 The Board finds, now that the arbitration of the TCGSL Gas Supply Contract Arbitration is complete, there is no further need to continue this account. In Chapter 6 of this Decision, the Board authorized the disposition of the entire $920,000 balance accumulated in the account.

Proposed New Accounts

8.1.19 Union requested the creation of two deferral/variance accounts for 1997, namely Unaccounted-For Gas Study Account and the Stress Corrosion Cracking Amortization Account.

Unaccounted-For Gas Study

8.1.20 Union's prefiled evidence indicated that Union's actual level of UFG gas as a percentage of throughput ranged from 0% to 0.73% for 1990 to 1995 with an average gas loss of 0.32% for the same period. Centra's level of unaccounted for gas as a percentage of throughput ranged from a gain of 0.24% to a loss of 0.26% with an average loss of 0.08%. The Companies noted that a report from the American Gas Association states that the average industry level for UFG is 1.6% of total inputs for 1994.

8.1.21 Union conducted a UFG study in December 1995 which included a review of a previous 1992 UFG study for possible sources of UFG identified at that time, and physical measurement and throughput activity since that time. Union also conducted an analysis to determine the reasons for increases in compressor fuel use during the winter of 1995-1996. The results of the study indicated that major monthly variances coincided with increases in demand. The study provided reasonable explanations for the increased UFG volumes required.

8.1.22 As a result of these studies Union has begun changing the transfer instrumentation system at its major metering stations from charts to electronic flow computers to address the Board's concerns expressed in E.B.R.O. 486-04.

8.1.23 Union agreed to examine alternative methodologies to allocate UFG separately for storage, the Dawn-Trafalgar System, other transmission and distribution functions and file the results in the 1998 rates case. As there were no costs included in Union's 1997 cost of service forecast for this study, Union requested a deferral account to cover the cost of the study.

SCC Amortization

8.1.24 Union proposed that the costs associated with testing its major transmission pipelines for SCC be deferred and amortized over a four year period to match the costs of system integrity and SCC activities with the anticipated benefits.

Positions of the Parties

8.1.25 The ADR Settlement Agreement stated that Union's evidence on the subjects of UFG and Stress Corrosion Cracking should be accepted. Parties recognized that no cost had been included in Union's 1997 forecast for the UFG examination, and accordingly supported Union's request to establish a deferral account.

Board Finding

8.1.26 The Board accepts as reasonable the establishment of the UFG deferral accounts for 1997 and the scope of the UFG studies as proposed by Union and supported in the ADR Agreement.

8.1.27 The Board accepts the establishment of the SCC deferral account for 1997 and expects the Companies to report on their SCC programs as directed in Chapter 2 of this Decision.

8.1.28 The Board has also found in Chapter 9 that unforecast C1 off-peak storage revenues and revenues from Other S&T Services should be captured in new deferral accounts for future disposition by the Board.

<u>Discontinued Accounts</u>

8.1.29 Union proposed the <u>closure</u> of the following deferral accounts subsequent to addressing current balances:

179-25 Deferred Interest (PGVA);
179-31 Deferred Interest (DCC);
179-41 Winter Peaking Service Cost; and
179-42 M12 Firm Transportation Revenue Deferral Account.

<u>Deferred Interest (PGVA) No. 179-25</u>

8.1.30 This account records simple interest on the opening monthly balances in Deferral Account 179-24 at the Board-approved cost rate of short-term debt. Union proposed to discontinue this account and record the interest on Deferral Account No. 179-24 directly to that account, since the balance of both accounts should be disposed of in the same manner as proposed for Deferral Account 179-24.

Deferred Interest (DCC) No. 179-31

8.1.31 This account records simple interest at the Board-approved short-term debt cost rate on the opening monthly balances in Deferral Account No. 179-30. Union proposed to discontinue this account and record the interest on Deferral Account No. 179-30 directly to that account, since the balance in both accounts should be disposed of in the same manner as proposed for Deferral Account 179-30.

Winter Peaking Service Cost Account No. 179-41 and
M12 Firm Transportation Revenue Deferral Account No. 179-42

8.1.32 Variances from the Board-approved forecast of Winter Peaking Service (WPS) costs for the period April 1, 1995 to March 31, 1996 are recorded in Account No. 179-41, while variances from the Board-approved forecast of M12 Firm Transportation Revenue for the period April 1, 1995 to March 31, 1996 are recorded in Account No. 179-42. These accounts were created specifically to address the disallowance of the Bright-Owen Sound transmission facilities expansion in the establishment of rates in E.B.R.O. 486 for fiscal 1996, and are therefore no longer required.

Positions of the Parties

8.1.33 The parties to the ADR Settlement Agreement accepted Union's proposals to close the Winter Peaking Service Cost Account No. 179-41 and the M12 Firm Transportation Deferral Account No. 179-42 subject only to a review of the disposition methodology of these balances.

8.1.34 The parties to the ADR Settlement Agreement agreed that Union's evidence on discontinuing Deferred Interest (DCC) Account No. 179-31 should be accepted subject to the parties' right to review the disposition methodology for the account.

Board Finding

8.1.35 The Board finds that Account Nos. 179-31, 179-41, and 179-42, including the Deferred Interest (PGVA) Account No. 179-25 not mentioned in the ADR Settlement Agreement, should be discontinued for Union's 1997 fiscal year, subject to its findings on the disposition of the fiscal 1996 balances.

8.2 DISPOSITION OF FISCAL 1996 ACCOUNTS - UNION

Account Balances

8.2.1 Union's updated evidence was filed in November 1996, and included forecast deferral account entries to December 31, 1996. The updated deferral account balances, including the proposed classification of these costs for recovery, are indicated in Table 8.1.

Table 8.1: Union: Forecast Deferral Account Balances as at December 31, 1996

Particulars	Account	Dec 31/96 Balance ($000)	Union ($000)	Gas Supply ($000)	Delivery ($000)	S&T ($000)
PGVA [1]	179-24	29,156		26,821	2,026	309
Deferred Interest (PGVA)	179-25	1,272		1,272		
Deferred Customer Credits/Rebates	179-26	(2,388)		(2,388)		
Payment of DCC	179-30	(4,391)		(4,391)		
Deferred Interest (DCC)	179-31	(90)		(90)		
C1 & M12 Transportation Net Revenue	179-34	(485)	(121)		(40)	(324)
Heat Value	179-38	1,246			1,246	
C1/M12 Storage Net Revenue	179-39	(4,268)	(427)		(3,841)	
Incremental Impact of Shared Services	179-40	(2,051)			(2,051)	
Winter Peaking Service Costs	179-41	2,300			335	1,965
M12 Firm Transportation Revenue	179-42	(1,463)			(213)	(1,250)
TCGSL Gas Supply Arbitration Costs	179-44	920		920		
Total Balance Allocation		**19,758**	**(548)**	**22,144**	**(2,538)**	**700**
Generic Hearing on System Expansion Deferred Costs [2]	179-43	217	N/A	N/A	N/A	N/A

1 See Table 8.2 for additional details
2 The Company proposed to retain the balance in this account for future disposition

Table 8.2: Forecast Components of Union's December 31, 1996 PGVA Balance

Particulars	Gas Supply ($000)	Delivery ($000)	S&T ($000)
PGVA Opening Balance - January 1, 1996	11,099		
Spot Gas	64,200		
Direct Purchase Imbalances	395		
Buy/Sell Supply	(2,300)		
Non-Compliance Penalties	(400)		
TCGSL Arbitration	(4,900)		
Energy In-Transit	900		
Other Gas Supply Variances	(4,471)		
E.B.R.O 486-04 Disposition	(22,800)		
E.B.R.O. 486-04 Disallowance	(5,140)		
January 1, 1997 Inventory Revaluation	(8,509)		
GLGT Toll Impacts	(1,253)	(2,647)	
Unaccounted For Gas/Compressor Fuel	(4,982)	4,673	309
TOTALS	**26,821**	**2,026**	**309**

8.2.2 For a typical residential customer consuming 3,100 m^3 of gas annually, Union noted that the above disposition of amounts deferred from prior periods would result in a $23.16 one-time net charge composed of a credit of $0.83 for storage and transportation and delivery-related deferred charges and a debit of $23.99 for gas supply- related deferred charges.

Disposition Methodology

8.2.3 Union proposed to allocate the gas supply related variance account balances to system sales customers, with the exception of a forecast amount of $395,000 related to direct purchase customers who have consumption in excess of the maximum allowable variance at contract year end. Union proposed that this forecast $395,000 be allocated on a customer-specific basis upon renewal of the customer's Gas Purchase Agreement or Gas Receipt Contract. Gas cost supply variance account balances include the 1996 balances in PGVA Deferral Account No. 179-24, the TCGSL Gas Supply Arbitration Cost Account No. 179-44, the Interest on PGVA Account No. 179-25, Deferred Charges/Credits/Rebate Account No. 179-26, the DCC and Downstream Differential Account No. 179-30, and interest on the DCC and Downstream Differential Account No. 179-31.

8.2.4 Fuel and unaccounted-for-gas costs of $4.982 million were proposed to be recovered from all customers on Union's system, except customers who supply their own fuel and allocation of unaccounted-for-gas.

8.2.5 Union proposed to allocate the $3.9 million Great Lakes Gas Transmission ("GLGT") Toll refund portion of the PGVA to system gas customers as well as buy/sell and T-Service customers with Western Canadian supply arrangements. The system gas customers will be credited with $1.253 million as part of the disposition of the PGVA balance, while buy/sell and T-Service customers will receive credits of $2.647 million refunded as part of direct purchase payments as a one-time adjustment.

8.2.6 The C1 and M12 Transportation Net Revenue Deferral Account No. 179-34 credit balance of $0.485 million is proposed to be allocated based on a 75:25 split consistent with the ADR Settlement Agreement, with the ratepayer share of $0.364 million allocated to Union’s in-franchise customers based on E.B.R.O. 486 design day levels. The ADR Settlement Agreement stated that this sharing recognizes Union's effort to market these services in light of available interruptible capacity, and also recognizes the forecast revenue levels for 1996 and 1997.

8.2.7 The proposed disposition of the $4.268 million credit balance in the C1 and M12 Storage Net Revenue Deferral Account No. 179-39 reflects a 90/10 customer/shareholder split, with the ratepayer share of $3.841 million allocated to customers based on E.B.R.O. 486 design day levels. Offsetting these credits to in-franchise customers is the $1.246 million debit related to the Heat Value Deferral Account No. 179-38, which is also allocated to customers using the E.B.R.O. 486 design day levels with the disposition based on annual delivery volumes. In addition, the parties to the ADR Settlement Agreement supported Union's proposal regarding the change in methodology for allocating the C1 Margin which entails changing the basis for allocation from contract demand to unutilized capacity.

8.2.8 Union proposed to allocate the net balance of the Winter Peaking Service Cost Account No. 179-41 on a capacity distance basis, which results in an allocation of $0.715 million to ex-franchise customers and $0.122 million to in-franchise customers, which is then allocated to rate classes on a design day basis and recovered over annual delivery volumes.

Positions of the Parties

8.2.9 Except for the issue of risk management and the disposition of the Purchased Gas Variance Account No. 179-24, the parties to the ADR Settlement Agreement agreed that Union's evidence on the disposition of the 1996 balances should be accepted.

8.2.10 With regard to Union’s risk management activities, Board Staff stated that there is no way of retrospectively judging the prudence of the risk management programs, given the reluctance of Union to provide the necessary detail of individual transactions. However, Board Staff was satisfied that Union followed the policies they presented to the Board in E.B.R.O. 486, and while this was an insufficient test of prudence, it is the only criterion available by which to review past risk management activities.

8.2.11 Board Staff stated that Union’s evidence was inconsistent in that it claimed that there was an "over allocation of PGVA costs to buy/sell customers" between this case and the completion of E.B.R.O. 486-04. Board Staff submitted that Union required additional supplies to support all customers, therefore "an allocation to all customers, other than bundled-T, equal to the variance for the volumes brought in the latter part of the winter and to refill storage to its normal March 31 control point should be made".

8.2.12 Union replied that costs deferred as a result of purchases caused by direct purchase customers were either recovered in the E.B.R.O. 486-04 Rate Order, or are provided for in the proposed rates and charges, so no further recovery is necessary.

8.2.13 ECNG opposed the allocation of costs related to direct purchase contract imbalances to Union's direct purchase customers since, in its view, it was a “major departure from the established practice in the recovery of costs from prior periods, in that Union is seeking to track these costs to individual customers” and “Union does not have the authority under its current Buy/Sell contracts or Bundled-T arrangements to collect gas costs from individual customers in excess of WACOG".

8.2.14 IGUA supported the Union's proposal regarding the allocation of load balancing costs for Union's direct purchase customers beyond their contract tolerances. IGUA supported Union's proposed disposition of the 1996 PGVA balance subject to Union providing the Board with a list of customers who will be affected by the rebalancing proposal, an estimate of the rebalancing costs, and customer-specific letters that describe the amount and the method of collection.

8.2.15 With regard to the forecast cost of $395,000 related to imbalances of direct purchase customers, NRG, PanEnergy and Direct Energy supported the principle that those who cause costs should pay them.

8.2.16 Kitchener argued that the PGVA was not intended to allow deferral of costs attributable to colder than usual weather, “or for the purpose of relieving Union of responsibility for its forecasts”. Therefore, in Kitchener's view, the incremental cost of the incremental supply due to colder than normal weather should not be deferred to the PGVA.

8.2.17 Union, in reply, argued that it continues to be responsible for weather risks as they relate to delivery related revenues, and the Company does not possess the ability to earn a margin on the gas supply commodity. The Utility submitted that the PGVA was established to remove the possibility of the risks and rewards associated with gas cost variances, and that Kitchener’s radically different treatment is not appropriate and should be given no consideration by the Board. Union noted that its position was consistent with the Board’s findings in its E.B.R.O. 492 Decision for Consumers' Gas.

Board Findings

8.2.18 The Board has previously found in Chapter 6 of this Decision that there is no evidence to indicate that Union has not adhered to the stated objectives of its Risk Management Plan and therefore the Board approves the proposed clearance of the PGVA amounts associated with this activity.

8.2.19 Based on the evidence the Board accepts Union's proposition that for the most part, sufficient recoveries have been made from buy/sell customers to offset the costs incurred by Union to provide these customers' unforecast gas requirements in the 1995-1996 winter period. However, the Board is of the view that, to the extent it is possible to directly assign the cost of load balancing to specific customers who are in an imbalance situation, then this is desirable from a cost causality standpoint. The Board therefore approves the direct assignment of these costs to these customers.

8.2.20 The Board has also observed in Chapter 6 of this Decision that it may be timely to reconsider the extent to which the Utilities should assume risks for variations between the Company's forecast of gas costs, and the actual costs incurred. Under the current practice gas costs have generally been treated as a pass-through cost, except in limited instances where the Board has made adjustments to reflect prudence concerns in the Utilities' gas supply management practices.

8.2.21 The margin earned on the delivery of the commodity is a separate matter. The Board agrees with the Companies that under the current practice, Union and Centra are responsible for weather related risks as they relate to the delivery component of their revenues. Until such time as it is determined to be reasonable to establish a variance account to capture delivery margin variances, the Board is of the view that it would be inappropriate to use the delivery margin earned by the Companies to reduce gas supply deferral account balances.

8.2.22 The Board notes that, except for the proposed disposition of Union's PGVA balance, the parties did not challenge either the balances in the deferral accounts, or the proposed disposition methodology. The Board has reviewed the disposition methodology and the forecast balances including the PGVA balances, and finds Union’s proposed disposition methodology and the balances in the accounts, including the PGVA, to be acceptable, subject to the Board's directions under the heading Method of Recovery at the end of this Chapter.

8.3 CENTRA: 1997 PROPOSED DEFERRAL AND VARIANCE ACCOUNTS

Continued Accounts

8.3.1 Centra proposed the continuation of the following deferral accounts:

179-53 Ontario Capital Tax Reassessment;
179-80 Firm Supply Purchased Gas Variance;
179-81 Spot Gas;
179-82 Discretionary (Spot) Transportation;
179-83 Compressor Fuel Gas;
179-84 TCPL Tolls;
179-85 Union Tolls;
179-86 Centra Transmission Holdings Tolls;
179-87 Centra Pipelines Minnesota Tolls;
179-88 Transportation Capacity Assignment; and
179-89 Heating Value.

8.3.2 The following accounts are discussed under the heading Disposition of Joint Activity Fiscal 1996 Accounts:

179-94 One-time Shared Services Integration Costs - Net of Amortization;
179-96 Incremental Impact of Shared Services (includes interest); and
179-40 Incremental Impact of Shared Services.

8.3.3 Except where otherwise noted, the parties either did not participate in the ADR discussion of a particular deferral account, accepted Centra's proposals, or did not oppose the continuation of the following deferral accounts for Centra's 1997 fiscal year.

<u>Ontario Capital Tax Reassessment Account No. 179-53</u>

8.3.4 This account records the difference between the amount of capital tax paid and the amount as reassessed by the Ontario Ministry of Revenue for the period from 1982 to 1990. Centra is still in the appeal process for this reassessment, which arises from the capital tax treatment of Distribution System Expansion Program grants. The Company did not propose to discontinue this account pending determination of Centra's appeal.

Firm Supply Purchased Gas Variance Account (Firm PGVA) No. 179-80

8.3.5 This account records the difference between Centra's actual monthly unit cost of firm gas supplies and the firm WACOG cost approved by the Board for inclusion in rates.

Spot Gas Deferral Account No. 179-81 and
Discretionary (Spot) Transportation Account No. 179-82

8.3.6 These two accounts capture variances between Centra's actual and forecast discretionary spot gas commodity and transportation costs.

Compressor Fuel Gas Account No.179-83

8.3.7 This account records price and volume variances from the fuel ratios approved for inclusion in rates. The fuel ratio represents the amount of compressor fuel required to transport a unit of gas through the TCPL system.

TCPL Tolls Deferral Account No. 179-84;
Union Tolls Deferral Account No. 179-85;
Centra Transmission Holdings Tolls Deferral Account No. 179-86; and
Centra Pipelines Minnesota Tolls Deferral Account No. 179-87

8.3.8 These accounts record variations between toll charges reflected in Centra's rates and the actual tolls paid by Centra. The Company explained that variations in the tolls result from decisions made by third parties and regulatory bodies, and therefore Centra cannot reasonably forecast the actual cost of these tolls.

Transportation Capacity Assignment Deferral Account No. 179-88

8.3.9 This account records proceeds from temporary unforecast assignments of transportation capacity to third parties.

Heating Value Deferral Account No. 179-89

8.3.10 This account records the differences between the forecasted heating value and the actual heating value experienced on the TCPL system for Rate 01, 10 and 16 customers.

Proposed New Account

8.3.11 Centra proposed to establish a TCPL Variance Charges deferral account to capture the expected daily and cumulative variance charges (overrun charges) relative to the proposed Limited Balancing Agreement ("LBA") applicable to Centra as an STS shipper on TCPL, net of any revenue related to the T-service load balancing service.

Positions of the Parties

8.3.12 The parties to the ADR Settlement Agreement agreed that the Companies' evidence on 1997 accounts should be accepted, subject to the parties' right to review the disposition methodology for accounts:

179-53 Ontario Capital Tax Reassessment;
179-83 Compressor Fuel Gas;
179-84 TCPL Tolls;
179-85 Union Tolls;
179-86 Centra Transmission Holdings Tolls;
179-87 Centra Pipelines Minnesota Tolls;
179-88 Transportation Capacity Assignment; and
179-89 Heating Value Deferral Account.

8.3.13 The proposed new TCPL Variance Account was not opposed by any party.

Board Finding

8.3.14 The Board accepts as reasonable for 1997 the above deferral accounts as proposed by Centra including the new TCPL Variance Account. The Board has, in its findings on Interruptible Rates and Policies in Chapter 10 of this Decision, found that Centra should include the net revenues received from the collection of the $\$5/10^3m^3$ charge on Rate 30 volumes in the Spot Gas Deferral Account.

Discontinued Accounts

8.3.15 The Company proposed to close the following accounts:

179-95 Calendar 1995 Revenue Requirement Outstanding; and
179-97 Deferred Charges re: Deductibility of Administrative and General Expenses.

Calendar 1995 Revenue Requirement Outstanding Account No. 179-95

8.3.16 This account recorded the 1995 Revenue Requirement Outstanding as authorized in the Board's E.B.R.O. 489 Decision With Reasons Part II. A charge of \$0.2747 million plus \$0.0295 million interest is proposed to be allocated to firm rate classes on the basis of rate class peak day and disposed of using Calendar 1996 delivery volumes.

Deferred Charges Re: Deductibility of Administrative and General Expenses Account No. 179-97

8.3.17 This account captured the effect of a Revenue Canada tax settlement, effective January 1, 1996, respecting the deductibility of administrative and general overhead for tax purposes. A charge of \$1.014 million grossed-up by \$0.771 million for income taxes, for a total disposition of \$1.785 million, is proposed to be allocated to all customers based on rate class peak day and disposed of using Calendar 1996 volumes.

Positions of the Parties

8.3.18 The parties to the ADR Settlement Agreement agreed that the Companies' evidence should be accepted subject to the parties' right to review the disposition methodology for the accounts.

Board Finding

8.3.19 The Board accepts as reasonable the closure of Deferral Account Nos. 179-95 and 179-97, subject to the Board's direction on the disposition of the 1996 balances.

8.4 DISPOSITION OF FISCAL 1996 ACCOUNTS - CENTRA

Account Balances

8.4.1 Centra's latest evidence was filed in November 1996, and included a forecast of deferral account entries to December 31, 1996. The November forecast of 1996 year-end deferral account balances, including the proposed recovery classification of these costs, is indicated in Table 8.3.

Table 8.3: Centra: Forecast Deferral Account Balances as at December 31, 1996

Particulars	Account	Balance ($000)	Supply-Related ($000)	Delivery ($000)	Transportation & Balancing ($000)
Firm Supply PGVA	179-80	2,133.3	2,133.3		
Spot Gas and Discretionary (Spot) Transportation [1]	179-81/82	13,913.0			13,913.0
Compressor Fuel Gas	179-83	(1,922.5)			(1,922.5)
TCPL Tolls	179-84	2,655.5			2,655.5
Union Tolls	179-85	(613.9)			(613.9)
Centra Transmission Holdings Tolls	179-86	(59.2)			(59.2)
Centra Pipelines Minnesota Tolls	179-87	(7.4)			(7.4)
Transportation Capacity Assignment	179-88	(2,032.4)			(2,032.4)
Heating Value	179-89	18.3			18.3
Calendar 1995 Revenue Requirement Outstanding	179-95	304.0		304.0	
Incremental Impact of Shared Services	179-96	(2,439)		(2,439.0)	
Deferred Charges Re: Deductibility of A&G Expenses	179-97	1,785.0		1,785.0	
Total Balance Allocation		**13,734.7**	**2,133.3**	**(350.0)**	**11,951.4**
Ont. Capital Tax Reassessment [2]	179-53	1,583.0	N/A	N/A	N/A

[1] This balance has been reduced by $10.061 million for supplies attributable to incremental Rate 25 and Rate 30 consumption.
[2] The Company proposed to retain the balance in this account for future disposition.

8.4.2 For a typical residential customer consuming 3,400 m^3 of gas annually, Centra noted that the above disposition of amounts deferred from prior periods would result in a $29.02 one-time net charge, which is comprised of $16.69 for transportation and balancing and delivery-related charges and $12.33 for gas supply-related deferral charges.

Disposition Methodology

8.4.3 Centra proposed to recover the Firm Supply PGVA balance using system gas volumes for Calendar 1996. Centra also proposed to use system gas volumes to recover the Spot Gas and Discretionary (Spot) Transportation account balances from all gas sales and bundled T-Service customers excluding Rate 16 and 25 customers.

8.4.4 The Compressor Fuel Gas account balance is proposed to be allocated to firm rate classes using sales and bundled T-volumes for Calendar 1996, as are all of the toll related deferral accounts. The TCPL Toll variance account balance, which relates to unrecovered transportation tolls from May 1, 1995 to June 30, 1996 is proposed to be allocated to rate classes based on volumes for this period; however the disposition will be over Calendar 1996 volumes.

8.4.5 The Transportation Capacity Assignment account balance is proposed to be allocated to firm rate classes in the same proportion as the capacity used to determine the TCPL toll charge. This methodology matches the credits for capacity brokering with the underlying firm capacity for the relevant rate classes.

8.4.6 The Heating Value Deferral Account balance is proposed to be allocated to Rate Classes 01 and 10 based on Calendar 1996 sales volumes.

Positions of the Parties

8.4.7 Except for the issue of risk management and the disposition of the balances in the Spot Gas Deferral Accounts Nos. 179-81 and 179-92, the parties to the ADR Settlement Agreement agreed that Centra's evidence on the disposition of the 1996 account balances should be accepted.

8.4.8 With regard to Centra's risk management activities, Board Staff stated that there is no way of retrospectively judging the prudence of the risk management programs, given the reluctance of Centra to provide the necessary detail of individual transactions. However, Board Staff was satisfied that Centra followed the policies they presented to the Board in E.B.R.O. 489, and while this was an insufficient test of prudence, it is the only criterion available by which to review past risk management activities.

8.4.9 With regard to Centra's Spot Gas and Discretionary (Spot) Transportation Deferral Accounts Nos. 179-81 and 179-82, ECNG noted that “failing the increase in prices achieved through the somewhat forced renegotiations Centra’s cost of gas PGVA account would have been approximately $10-million higher if the sale had been made at the originally contracted price.” ECNG submitted that it was not fair that interruptible customers should “bear the extra $10-million burden that has been placed on them for simply needing their predictable, projected summer deliveries”. ECNG argued that the Board should rescind Centra’s summer “interruptible” price increases and add those amounts to the Spot Gas deferral account, so it is distributed to all bundled service customers.

8.4.10 Board Staff disagreed with ECNG's proposition to have Centra refund the revenues it earned from the authorized overrun charges and unauthorized overrun charges on Rate 16 and 25 customers, and the Rate 30 revenues earned from Rate 16 and 25 customers. Board Staff viewed these revenues as “correctly used as an offset to balances related to variances from these rate classes".

8.4.11 IGUA supported ECNG’s argument regarding the reallocation of $10 million in costs to the Spot Gas deferral account, since IGUA believed that the direct assignment of supply to interruptible customers is inappropriate. IGUA submitted that "Centra [should be required] to account to its Rate 16 and Rate 25 customers for any amounts which it has collected through its administration of Rates 16 and 25 and of Rate 30 in excess of the actual costs incurred by Centra to obtain spot gas to provide service to those customers".

Board Findings

8.4.12 The Board has previously found that there is no evidence to indicate that Centra has not adhered to the stated objectives of its Risk Management Plan and therefore it approves the proposed clearance of the Firm Supply PGVA balances associated with this activity.

8.4.13 The Board in its findings on Interruptible Rates and Policies in Chapter 10 of this Decision has directed Centra to allocate margins earned from the sale of the gas commodity to those renegotiated Rate 25 and Rate 30 customers who paid gas commodity charges in excess of Centra's delivered cost of these supplies. However, the Board did not make any adjustments to the Spot Gas deferral accounts as it found Centra to be acting within the terms of its contracts and performing actions consistent with the current rate design for the interruptible rate classes. While circumstances resulted in significant costs being incurred by interruptible customers in fiscal 1996, the application of this same rate structure has resulted in significant benefits to these customers over the last several years. The Board reiterates its view that those customers choosing not to exercise their alternate fuel capability when faced with periods of extended interruption, should bear the incremental costs associated with retaining natural gas supply.

8.4.14 The events occurring in the 1996 fiscal year have persuaded the Board that a review of interruptible rates and the operation of the interruptible rate classes is required. In Chapter 10 of this Decision the Board has ordered such a review for the next rates case.

8.4.15 Except for Centra's risk management as it relates to the Firm Supply PGVA and the disposition of the balances in the Spot Gas deferral accounts, parties did not challenge either the balances in the deferral accounts, or the disposition methodology. The Board has reviewed the balances in the accounts and the disposition methodology proposed by Centra and finds these to be acceptable, subject to the Board's directions under the heading Method of Recovery at the end of this Chapter.

8.5 UNION AND CENTRA: 1997 JOINT ACTIVITY PROPOSED DEFERRAL ACCOUNTS

8.5.1 The Companies proposed the creation of two joint deferral accounts:

179-46 Direct Purchase Customer Information Package; and
179-48 Utility Ancillary Services Studies Cost Allocation Study.

Positions of the Parties

8.5.2 The parties to the ADR Settlement Agreement supported the creation of a deferral account to record incremental costs associated with studies related to ancillary services including, but not limited, to the cost of consultants and other third party expertise.

8.5.3 The parties to the ADR Settlement Agreement also supported the creation of a deferral account to record incremental costs associated with development and implementation of an ABC T-Service Customer Information Package similar to that developed by Consumers' Gas.

8.5.4 Some parties proposed the creation of a joint DSM deferral account and a joint Lost Revenue Adjustment Mechanism variance account, in order to provide the Company with an incentive to aggressively pursue DSM opportunities.

Board Findings

8.5.5 The Board, in this Decision, has accepted the Companies' proposals regarding the preparation of the Utility Ancillary Services Studies Cost Allocation Study and development/implementation of the Direct Purchase Customer Information Package. As the cost of these activities is likely to be significant and cannot be forecast with a sufficient degree of comfort, the Board authorizes the proposed new deferral accounts to capture the costs of these activities.

8.5.6 The Board found in Chapter 4 that neither the proposed DSM deferral account nor the Lost Revenue Adjustment Mechanism variance account are necessary, and has not accepted the creation of these accounts.

8.6 DISPOSITION OF FISCAL 1996 JOINT ACTIVITY ACCOUNTS

8.6.1 The Companies proposed the closure and disposition of the balances in accounts related to the Shared Services initiative: Centra/Union One-Time Costs Deferral Accounts No. 179-36, and 179-37 for Union and 179-94 for Centra.

8.6.2 These accounts recorded the initial costs required to implement Shared Services and interest on these costs until the implementation costs are fully amortized into the cost of service. In E.B.R.O. 486/489 total One-Time Shared Services O&M costs were forecast to total $11,348,000 and were to be amortized over Calendar years 1995, 1996 and 1997 in proportion to the forecast savings from the Shared Services initiative.

8.6.3 In the current proceeding the Companies forecast a total cost reduction of $1,998,000 from $11,348,000 to $9,599,000 in One-Time Shared Services O&M costs associated with communication, relocation/severance, retraining/alignment, CIS and carrying charges.

8.6.4 The Companies proposed that the $4,569,200 joint balance remaining be allocated based on the allocation percentages approved in E.B.R.O 486/489 of 42.4% or $1.937 million for Centra and 57.6% or $2.632 million for Union. Based on the Companies' updated evidence of August 30, 1996, the balances of the One-Time Shared Services Costs Deferral Accounts decreased resulting in a revised allocation of $0.544 million for Centra and $0.739 million for Union, leading to deferral account balances of $1.393 million for Centra and $1.893 million for Union.

8.6.5 In Calendar 1997 all one-time costs will have been fully amortized into the cost of service; therefore the Companies proposed that these accounts be discontinued as of December 31, 1997.

<u>Incremental Impact of Shared Services Deferral Account 179-40 for Union and 179-96 for Centra</u>

8.6.6 These accounts record the incremental O&M cost savings forecast to be received by Centra for Calendar 1996 and by Union for the fiscal 1997 period. In E.B.R.O.

486/489 O&M cost savings were forecast to accumulate to total costs of $4,376,000 in Calendar 1995, $7,511,000 in Calendar 1996 and $13,502,000 in Calendar 1997 respectively. Given the uncertainty as to whether Union and Centra would file for new rates, the Board directed Centra to establish Deferral Account No. 179-96 and make monthly entries of $195,392 effective January 1, 1996 and directed Union to establish Deferral Account No. 179-40 and make monthly entries of $221,833 effective April 1, 1996. The balance in Centra's Account No. 179-96 is $2.439 million, while Union's Account No. 179-40 balance is $2.051 million. The Companies requested that these accounts be closed subsequent to the final disposition of the accumulated balances.

8.6.7 In this proceeding the Companies forecast Shared Services O&M cost savings and revenue enhancement of $13,771,000 in 1997. The Companies proposed to allocate the Incremental Impact of Shared Services Deferral Account 1996 closing balances on the basis of in-franchise design day demand. Calendar 1997 is the first year the full impact of all incremental O&M cost savings from Shared Services will be realized. The Companies explained that separate tracking of incremental savings was no longer required.

Positions of the Parties

8.6.8 The parties to the ADR Settlement Agreement agreed that the Companies' evidence and proposals in connection with the Shared Services deferral accounts should be accepted. The parties further agreed to close the Shared Services deferral accounts subject only to an examination of the balances in those accounts.

Board Finding

8.6.9 In Chapter 3 of this Decision the Board has found that the Shared Services deferral accounts should be closed and the balances as of December 31, 1996 disposed of to all customers, as proposed by the Companies.

8.7 METHOD OF RECOVERY--CUSTOMER IMPACTS

8.7.1 The Companies originally proposed to recover the deferral account balances through a one-time charge based on the most recent twelve months of actual consumption. The Companies noted that the merits of this approach include the timely disposition of balances, matching the recovery of costs to those customers who caused them, and minimizing the number of adjustments to customer bills.

8.7.2 The Companies accepted the views of several participants that the use of a rate rider approach would mitigate customer impacts. However, the Companies argued in their Motion for Interim Gas Costs that the Board should adjust the rate rider in the Board's final order to reflect the actual balance in the deferral accounts as of December 31,1996, rather than posting the year-end balance to 1997 accounts and only disposing of the actual amounts recorded up to September 1996.

Positions of the Parties

8.7.3 Board Staff agreed that there is merit in the idea of minimizing rate shock by the use of a rate rider. Board Staff proposed to delay the implementation of the rider. Board Staff proposed to use a one-time charge to dispose of the portion of the 1996 PGVA balances accumulated from January 1, 1997, to the time of the Board's final Decision, with the remainder of the actual balances at December 31, 1996 collected over the remainder of the 1997 calendar year. Board Staff felt that this approach minimized the rate shock to customers, eliminated any readjustments that might be necessary if the rider was set based on forecast balances, and maintained the twelve month recovery period for the PGVA disposition. Board Staff felt this would be an appropriate treatment for all Centra's gas supply related deferral accounts as well.

8.7.4 CAC agreed with Board Staff's position, with the caution that rate riders may be an easy way to deal with some problems, but do raise intergenerational equity concerns.

8.7.5 IGUA felt that the total deferral account balances would not likely change materially, so in its view, it was unnecessary to wait to get the exact amounts. IGUA preferred a rate rider since it is prospective in nature, would enable IGUA's members to account for the adjustment in their budgeting activities and any resulting intergenerational inequity is not undue.

8.7.6 ECNG argued that the PGVA balance disposition should reflect the actual balances to the maximum extent possible.

8.7.7 OCAP argued that, in order to smooth the impact on lower income customers, the use of a rate rider for deferral account disposition may be appropriate. NRG, PanEnergy and Direct Energy also preferred the rate rider, and suggested that it could be limited to a shorter period, perhaps ending before the next heating season.

8.7.8 Kitchener supported a rate rider over a one-time charge. Kitchener noted that the one-time charge was unpopular and disruptive. Kitchener argued that the one-time charge did not fully address cost causality as customers who move outside Union's franchise area during the year do not pay under either a one-time charge or rate rider, and customers with balances of less than $10 are not charged. Kitchener also noted that uncollectible costs are deferred for disposition in a future hearing and would not be imposed on the customers who caused the costs.

Board Findings

8.7.9 The Board notes that there is strong support in the current proceedings for the use of a rate rider rather than a one-time charge for recovery of deferral account balances accumulated in 1996. The Board is of the view that it is inappropriate to view the disposition of deferral account balances in isolation. The respective revenue requirements of Union and Centra, and the charges/credits resulting from the difference between the rates currently in effect and the rates that result from this Decision from January 1, 1997 to May 31, 1997, must also be considered.

8.7.10 In the case of Union, the Board has determined that a revenue excess will significantly reduce the impact of the deferral account disposition. However, the Board has reviewed the allocation of both the revenue excess and the deferral account disposition, and finds that a one-time charge is excessive. The Board has determined that the net charge would be best collected as equal monthly payments in July and August 1997.

8.7.11 In Centra's case, the Board has determined that the magnitude of the Board-approved revenue deficiency, as allocated subject to further adjustments made by the Board, in conjunction with the forecast one-time charge, will cause serious problems for customers to manage. The Board has determined that the most appropriate means of collection would be to authorize four equal payments to spread the one-time charge evenly over the four month period from July 1997 to October 1997. This will enable Centra to recover these charges before bills begin to increase significantly for heat sensitive customers.

8.7.12 The Companies shall dispose of the actual balances accumulated to December 31, 1996. In order to assist in the review of the difference between the forecast balances discussed in the hearing and the actual balances, the Company shall report the difference in the Companies' next rates cases.

9. UNION COST ALLOCATION AND RATE DESIGN

COST ALLOCATION METHODOLOGY

9.0.1 Union proposed a number of changes in cost allocation methodology for the 1997 test year. The Company indicated that in addition several other issues arose from intervenor concerns and/or Board directives in prior rate cases. The resulting issues were:

- Allocation of costs to SBUs;
- Direct assignment of gas supply administration costs;
- S&T: M12 cost allocation;
- Mileage based cost allocation and treatment of east end deliveries;
- Allocation of Dawn Compressor Station carrying costs;
- Allocation factors for demand related costs;
- Allocation of storage revenues;
- Allocation of distribution capacity costs; and
- Direct assignment of DSM costs (also Centra).

9.0.2 The allocation of costs to SBUs and the direct assignment of gas supply administration costs were matters agreed to as part of the ADR Settlement Agreement. The other issues were not fully resolved in the ADR settlement process and in addition, the issue of M9 distribution sales promotion costs and uncollectible account costs arose in the ADR settlement process and was addressed in the hearing.

9.1 ALLOCATION OF COSTS TO SBUS

9.1.1 In its E.B.R.O. 486 Decision the Board directed the Company to examine the feasibility of allocating rate base between Union's storage and transportation SBU and its distribution SBU and to report its conclusions in the next rates case.

9.1.2 The Company indicated that its rate base allocation was based on customer classes and the SBU structure does not correspond directly to customer classes. However, the results of the Company's cost allocation study could be used to allocate the rate base between the storage and transportation SBU and the distribution SBU using annual customer volume to complete the inter-class allocation.

9.1.3 Based on the Company's original forecast of Rate Base in May 1996, this approach would result in a 35.74% allocation to storage and transportation SBU and a 64.26% to distribution SBU of the original forecast 1997 Rate Base.

Positions of the Parties

9.1.4 In the ADR Settlement Agreement the following parties agreed with Union's evidence on the allocation of costs and rate base to the storage and transportation and distribution SBUs: Kitchener, NOVA, ONA, Board Staff, CAC, ECNG, NRG, IGUA, OCAP, Universities.

Board Finding

9.1.5 The Board finds that, given Union's declared plans for separation of the gas merchant function, and other possible changes to its corporate business structure, Union should continue to work on a proper methodology consistent with the studies agreed to for ancillary programs, for allocation of rate base to SBUs or to affiliates, so that there is a sound basis for the Board's consideration of any proposed allocation of costs among components of the Companies' business structure.

9.2 DIRECT ASSIGNMENT OF GAS SUPPLY ADMINISTRATION COSTS

9.2.1 Union proposed to directly assign the incremental costs associated with the administration related to each gas supply alternative (buy-sell, T-service, bundled-T and system supply) to its rate classes. A total of $1,533,527 is associated with Union's gas supply administration exclusive of direct purchases. A total of $589,984 is associated with administering direct purchase agreements in the regular rate as well as industrial markets. Included in the system supply related costs is the gas supply commodity portion of the allowance for uncollectible accounts.

ADR Settlement Agreement

9.2.2 The following parties participated in the discussion of this issue: Kitchener, Schools, Terra, Nova, ONA, Board Staff, CAC, ECNG, NRG, IGUA, OCAP and Universities. The parties agreed that the Company's evidence on this subject should be accepted.

Board Finding

9.2.3 The Board accepts the Company's proposed assignment of gas supply administration costs for 1997 with the exception of the review of the allocation of the allowance for uncollectible accounts to the M9 rate class which is addressed later in this Chapter.

9.3 S&T: UNION M12 COST ALLOCATION

Background

9.3.1 Union’s Rate M12 is the rate charged to cross-franchise shippers for firm long-term services related to transportation of gas on the Dawn-Trafalgar System.

9.3.2 In its E.B.R.O. 486 Decision the Board directed Union to prepare an M12 cost allocation study to ensure that there is no cross subsidy among rate classes which use the Dawn-Trafalgar System (including storage) and to present this study in its next main rates case. In October, 1995 R.J. Rudden Associates Inc (“RJRA”) was retained by Union to undertake a review of the existing methodology based on the Company's rate design evidence presented in E.B.R.O. 486.

9.3.3 RJRA's report examined the following aspects of the Dawn-Trafalgar System:

- ! the operational characteristics and services offered;
- ! Union's overall cost study structure and framework;
- ! Union's principles and methods for functionalization, classification and allocation of costs:
- ! the derivation of Union's allocation factors;
- ! application of cost study results; and
- ! cross subsidization and rate design issues.

9.3.4 RJRA's overall assessment was that*:*

> *"the conceptual underpinnings and resulting methodologies upon which Union's cost allocation study is based are well conceived, thorough and reasonable: however the presentation of the cost study ... fails by not providing sufficient detail to allow an outside party to understand, trace and verify the study's underlying assumptions and computational process"*.

9.3.5 In an attempt to remedy this deficiency, Union filed supplementary evidence to aid parties to the proceeding in completing independent reviews of the cost allocation and rate design of services offered on the Dawn-Trafalgar System.

9.3.6 The RJRA report did not recommend any changes to Union's current cost allocation for S&T services or the ex-franchise (M12) allocation of costs of the Dawn-Trafalgar System.

ADR Settlement Agreement

9.3.7 The parties to the ADR settlement process failed to reach a consensus on the following specific issues:

- C mileage based cost allocations;
- C treatment of east end deliveries; and
- C allocation of Dawn Compressor Station carrying costs.

Intervenor Evidence

9.3.8 TCPL and Consumers' Gas, both large ex-franchise users of the Dawn-Trafalgar System, filed evidence and presented expert witnesses who disagreed with certain aspects of Union's Dawn-Trafalgar System cost allocation and rate design methodology for M12 customers.

9.3.9 TCPL's areas of disagreement with Union's cost allocation study and its endorsement by RJRA, were the allocation of mileage credits related to *east end deliveries* to in-franchise customers and the method of *allocation of Dawn Compressor Station costs* to the S&T services provided by Union.

9.3.10 Consumers' Gas' areas of disagreement were *mileage based cost allocation*, the treatment of *east end deliveries* and the *design day forecast demand* for in-franchise and ex-franchise customers.

9.4 MILEAGE BASED COST ALLOCATION AND TREATMENT OF EAST END DELIVERIES

9.4.1 Union's evidence was that the Dawn-Trafalgar System is a bi-directional, multi-functional, integrated pipeline system. The system has a 1997 peak capacity requirement of 131,977 10^3m^3/day (plus fuel). The actual design capacity is 129,997 10^3m^3/day and the balance is met by Winter Peaking Service ("WPS") deliveries from TCPL at Parkway. Approximately 94,584 10^3m^3/day of contracted M12 volumes and 37,393 10^3m^3/day of in-franchise volumes (less 1,980 10^3m^3 of WPS) are transported easterly from Dawn with the balance of the in-franchise deliveries being delivered in part by a swap of east end deliveries with M12 volumes flowing from Dawn (14,122 10^3m^3/day).

9.4.2 With regard to *mileage based cost allocation* Union's evidence was that its cost study allocates costs of transportation on the Dawn-Trafalgar System based on a "commodity-kilometer" cost allocation factor using the principle that the system costs are mileage sensitive. Union's staff and outside experts contended that allocating costs based on the peak design day demand weighted by the distance that demand volumes travel from Dawn, provides the best match between cost causality and tolls.

9.4.3 RJRA's expert supported Union's methodology and cited the following reasons why *mileage based cost allocation* rather than a "postage stamp" allocation, i.e. without regard to distance of haul, was appropriate for the allocation of transportation costs on the Dawn-Trafalgar System:

- the system has a distinct west-east orientation; i.e. at peak design day conditions gas flows from west to east are much greater than at other times of the year;
- there is a need to transport M12 shippers' volumes over much greater distances than volumes for Union's in-franchise customers; and
- the location of users' demands is such that increasing the distance the gas travels increases the facilities required and hence the level of costs per unit of gas transported.

9.4.4 Consumers' Gas retained Energy Group Inc. to examine Union's mileage based cost allocation and the treatment of east end deliveries. Its expert concluded that there was no proper basis for the *mileage based cost allocation*. He advocated, given the design and operation of the Dawn Trafalgar System and its characteristics compared to other integrated systems, that costs should be allocated on a postage stamp basis. He also concluded that costs should be allocated to all Dawn-Trafalgar delivery requirements, including east end deliveries, as if they originated at Dawn, consistent with the integrated nature of the system and the physical flow of gas on the peak winter design day.

9.4.5 With regard to *east end deliveries*, Union's evidence was that at design day conditions (131,977 10^3m^3/day plus fuel) the flow is totally west-east with 115,875 10^3m^3 of the peak demand being met by the design capacity of the system and the balance, (approximately 16,000 10^3m^3) by Union contracting for TCPL WPS (1,980 10^3m^3), through arrangements with certain in-franchise buy/sell and T-service shippers to have their gas delivered at Parkway and other east end delivery points, and through Union's own in-franchise system gas deliveries (14,122 10^3m^3). These volumes are exchanged with volumes flowing from Dawn to allow the total demand from both in-franchise and ex-franchise (M12) customers to be met.

9.4.6 Union allocates transportation costs to its in-franchise customers as if the east end volumes are delivered at 'Parkway' (actually five east end delivery points) and then transported west for delivery to its in-franchise delivery points. Therefore only a small portion of transportation costs is allocated to these volumes, compared to what the transportation cost allocation would be if the volumes had moved from Dawn. The balance of the in-franchise volumes are in fact transported from Dawn.

9.4.7 Union allocates transportation costs to its ex-franchise customers based on delivery of their total volume at Dawn and transportation easterly to the east end delivery points specified in their contracts.

9.4.8 The issue related to *east end deliveries* is that Union deems that a volume of gas equivalent to the east end deliveries, enters the system at Dawn and moves to three east end delivery points for redelivery to in-franchise customers and not to the ex-franchise customers. The lower transportation costs allocated to the *east end deliveries* for in-franchise customers result in mileage credits for the east end deliveries, which are streamed to the in-franchise customers. The Delivery Commitment Credit (DCC), Obligated Demand Premium (ODP) costs and TCPL demand charges associated with the east end delivery volumes are charged to the account of in-franchise customers only.

9.4.9 Both the east end delivery volumes (14,122 10^3m^3) and WPS volumes (1,980 10^3m^3) are functionalized as capacity (transmission) related and are not commodity related.

9.4.10 Union noted that the *east end deliveries* are a fundamental part of the peak design of the Dawn-Trafalgar System which allows the design capacity of the system to be smaller than otherwise required if all volumes had to move from Dawn under peak design day conditions. This reduction in capacity and facilities benefits all users of the Dawn-Trafalgar System, including ex-franchise shippers (Rate M12) and in-franchise customers, in the form of lower rates.

9.4.11 TCPL retained Tibor Haynal and Associates and Thomas R. Hughes & Associates to present evidence in support of its proposals for alternative cost allocations. In the opinion of TCPL's experts, the purpose of east end deliveries is to provide for delivery point flexibility, for example at either Dawn or Parkway and in view of this flexibility, such deliveries should be treated as gas supply (commodity) related rather than transmission (capacity) related. Union's current allocation of costs does not, in TCPL's experts' view, properly reflect the principle that cost responsibility tracks cost causation. As a result, Union has over-allocated costs to the ex-franchise (M12) customers by departing from the physical operation of the system and deeming that east end deliveries, which carry no Dawn-Trafalgar System cost, are flowing only to in-franchise customers; they are in fact swapped with M12 shippers' volumes and actually flow eastward from Parkway as part of M12 contract volumes.

9.4.12 TCPL's witnesses stated that, in their opinion, Union's cost study should be amended to allocate the savings resulting from east end deliveries to both the in-franchise and to the ex-franchise (M12) customers who make the exchange of east end delivery volumes possible. According to TCPL, if its proposals were accepted, $15.955 million of costs would be reclassified as transmission related.

Positions of the Parties

9.4.13 Union submitted that it uses direct deliveries of gas to the east end of its system to reduce the size of the facilities to serve all customers and that Union is able to rely on those deliveries for the purposes of designing the system because of the contractual arrangements which it and its direct purchase customers have with TCPL. Union submitted that both TCPL and Consumers' Gas' witnesses had conceded that the volumes involved in east end deliveries are, for the purposes of design of the system, properly treated as being delivered to the east end of the system.

9.4.14 Union's position was that it has contracted for the delivery of in-franchise gas supplies to the east end and that it is neither fair nor reasonable to suggest that Union's customers should also be allocated the costs of the Dawn-Trafalgar System to transport an equivalent volume from Dawn to Parkway.

9.4.15 TCPL submitted that the commodity-kilometer allocation units used for apportioning Dawn-Trafalgar System costs between in-franchise and ex-franchise customers should track system design and operations. This would require that east end deliveries be viewed as a part of the peak design winter day and allocated to the benefit of both groups of customers.

9.4.16 In support of its position TCPL submitted that:

- Union's cost allocation methodology is not based on actual system design and operation since there are no physical deliveries to in-franchise customers from Parkway on the peak design winter day;

- Union's operating characteristics are not unique; many U.S. LDC's operate integrated systems which provide service to both intrastate and interstate shippers;

- Union's DCC, ODP and TCPL demand charge expenditures are gas supply functions and should not be treated as transmission capacity related; and

- the RJRA report does not support Union's east end delivery cost allocations in that it supports distance based tolling on the Dawn Trafalgar system, but does not apply this methodology to the in-franchise volumes on the peak design winter day.

9.4.17 In conclusion, TCPL submitted that the Board should not perpetuate the subsidy arising from misallocation of Dawn-Trafalgar System transmission costs which, by TCPL's calculation, results in Ontario ratepayers overpaying for transportation of gas by $14.1 million. The Board should order Union to allocate Dawn-Trafalgar System transmission costs based on measuring the flows from Dawn, their actual point of origin, on the peak winter design day.

9.4.18 Consumers' Gas submitted that although a unit cost study had not been done, there were certain characteristics of the Dawn-Trafalgar System which supported a change to a postage stamp cost allocation:

- no other North American pipeline of a comparable length uses mileage based cost allocation and mileage based allocation is usual only for pipelines with a length of over 300-500 miles (480-800 kilometers);.

- bi-directional pipelines do not use mileage for cost allocation purposes; and

- pipelines with mileage based cost allocation "telescope" with distance in that the number of loop lines decreases as distance increases; so regulators apply mileage based cost allocation to ensure that the upstream capacity cost is also allocated to downstream customers who also benefit from the upstream capacity. The

Dawn-Trafalgar System does not 'telescope' and is most heavily looped in the centre.

9.4.19 Consumers' Gas submitted that elimination of mileage from the cost allocation factor would put in-franchise and ex-franchise customers on the same basis and that Union had admitted that, in essence, in-franchise customers were currently all paying as if their deliveries were all made at a point near London which is equivalent to a postage stamp rate. Adopting Consumers' Gas' proposal would also eliminate the dispute over the allocation of the mileage credits associated with east end deliveries.

9.4.20 The cost rebalancing advocated by Consumers' Gas would shift $19.3 million in costs to Union's in-franchise customers. Although this is a very significant cost shift, Consumers' Gas submitted that Ontario customers would benefit in two ways. The in-franchise customers of Consumers' Gas and Centra would benefit from cost savings resulting from lower M12 rates. All in-franchise customers of Union, Centra and Consumers' Gas would benefit from the TCPL cost savings that would result. If the Board felt the rate impact of levelling the playing field was too large, the change could be phased in over two years.

9.4.21 Consumers' Gas supported TCPL's position that, absent adoption of a postage stamp cost allocation, east end delivery mileage credits should be allocated to all customers. It also argued that the DCC and ODP and TCPL demand charges were gas supply related and as such should continue to be allocated entirely to in-franchise customers.

9.4.22 CAC and OCAP supported Union's current S&T cost allocation methodology, including the M12 cost allocation, and submitted that the Board should reject the alternatives proposed by Consumers' Gas and TCPL.

9.4.23 In IGUA's submission the existing transmission system and facilities paid for by in-franchise customers upstream of Parkway operate to produce the equivalent of a stand-alone west-east system with no upstream facilities at Parkway. It argued that since a primary purpose of the west-east transmission system is to carry M12 demands from Dawn to Parkway, it is fair and reasonable to allocate the costs in the manner Union proposes.

9.4.24 IGUA submitted that the costs of the transmission facilities upstream of Parkway, which are used to provide east end deliveries to M12 customers during peak periods, together with the costs of the Dawn-Trafalgar System which are allocated to in-franchise customers comprise, in total, a reasonable share of the total costs incurred to support the transmission capacity which Union uses to provide in-franchise customers with distribution services. Accordingly, Union's allocation of costs between in-franchise and ex-franchise customers based on a distance-weighted demand ought to continue to be approved.

9.4.25 Board Staff submitted that although Consumers' Gas experts' criteria for the application of postage stamp rates are in general appropriate, these criteria do not recognize the inescapable truth that the Dawn-Trafalgar System is primarily designed to store gas for winter consumption and deliver that gas on design day to various take off points on the pipeline system. Therefore on design day it operates to deliver gas in a single direction - from Dawn easterly.

9.4.26 Board Staff submitted that the other criteria for using postage stamp rates which had been suggested by Consumers' Gas' experts, were inappropriate for application to the Dawn-Trafalgar System, and that the existence of large storage pools at one end of the system may have a significant impact on how the system is configured. Board Staff therefore did not support the use of postage stamp rates for the Dawn-Trafalgar System.

9.4.27 Board Staff also submitted that Union's calculation and allocation of the benefits of east end deliveries is appropriate and consistent with its mileage based cost allocation.

9.4.28 In Board Staff's submission, the counter arguments of TCPL's and Consumers' Gas' experts failed in three ways:

- the costs of the east end deliveries, including premiums are paid for by the in-franchise customers to obtain gas deliveries for their use;
- the ex-franchise customers deliver their gas at Dawn for transportation to points east on design day; and

- if there were no ex-franchise demands to be met, east end delivered gas would flow westward to serve the in-franchise customers of Union.

Board Findings

Storage and Transportation Cost Allocation Study

9.4.29 The Board finds that in general, the review of the Company's cost allocation study was useful and that the recommendations made by RJRA to improve the transparency of the methodology are helpful and worthy of expeditious implementation by Union.

9.4.30 In its subsequent Findings, the Board has noted several areas which require further review in light of the evidence in this case, but these should not be considered as a reason to delay the implementation of the RJRA's recommendations.

Mileage Based Cost Allocations

9.4.31 The Board is satisfied that Union's cost allocation study properly reflects the peak winter design day. The unchallenged evidence is that at design conditions the system operates as a unidirectional west-east transmission pipeline. The fact that the pipeline is multi-functional and operates as a bi-directional integrated pipeline at other times, does not change the fact that on design day, both in-franchise and ex-franchise gas is flowing easterly and that it requires considerable upstream capacity and additional compression to provide delivery service to the M12 customers at Parkway and other east end delivery points specified in their contracts.

9.4.32 The Board accordingly continues to find Union's methodology based on a commodity-kilometer allocation factor, appropriate for allocating the costs of the Dawn-Trafalgar System.

Treatment of East End Deliveries

9.4.33 The Board accepts Union's position that east end deliveries and WPS are an integral part of the peak day design of the Dawn-Trafalgar System and therefore are appropriately classified as transmission-related costs rather, than as TCPL and Consumers' Gas have suggested, commodity-related costs.

9.4.34 In the Board’s view, the issue raised by TCPL and Consumers' Gas is not whether the M12 shippers are paying too much for the service they receive, but rather whether they should receive an additional benefit from the east end mileage credits because the existence of their volumes moving from Dawn allows the in-franchise customers to be served by swapping these volumes with the east end deliveries.

9.4.35 The Board believes that the evidence in this case indicates that as long as the Dawn-Trafalgar System is an integral part of the utility plant needed to serve its in-franchise customers, the current allocation of the east end mileage credits is appropriate. First, the east end volumes are owned by Union and its in-franchise customers who pay the TCPL delivery tolls. Second, Union pays the DCC and ODP on these volumes, as for all peak deliveries to ensure delivery, and also arranges its nominations to ensure peak day east end delivery of the volumes. The Board finds it persuasive from a cost/benefit matching point of view that the DCC, ODP and TCPL tolls are paid only by in-franchise customers.

9.4.36 The Board finds that the streaming of the benefits of east end deliveries to in-franchise customers is reasonable, given that the in-franchise customers pay all the costs associated with the delivery of these volumes to the east end and then pay a mileage based charge for a deemed westerly delivery. In the Board's view it would not be just and reasonable for the in-franchise customers to pay any portion of the costs to move equivalent volumes from Dawn.

9.4.37 The Board finds that the fact that at design conditions, delivery of east end volumes (14,122 10^3m^3) to in-franchise customers requires a swap with volumes being transported from Dawn for M12 customers is insufficient reason for the M12 shippers to share in the east end mileage credits and hence pay lower net tolls for the delivery of their contract volumes to their contracted east end delivery points. The M12 customers receive what they pay for: delivery of their total design day contract demand from Dawn to Parkway, or other east end delivery points as specified in their contracts. The costs allocated by Union to the M12 rate class are, in the Board’s view, appropriate.

9.4.38 The Board notes that both M12 shippers and Union's in-franchise customers benefit from east end deliveries by the fact that the design capacity of the system is smaller by 16,000 10^3m^3/day and the associated utility plant rate base is significantly reduced.

9.4.39 For the purposes of setting 1997 test year rates, the Board finds Union's current treatment of east end deliveries and the allocation of costs to the M12 rate class to be just and reasonable.

9.5 ALLOCATION OF DAWN COMPRESSOR STATION CARRYING COSTS

9.5.1 Union's evidence with regard to classification of Dawn Compressor Station carrying costs, was that the Dawn Compressor Station provides peak design day service for storage injection and withdrawals and for easterly transmission of ex-franchise deliveries received at Dawn. The Station has six compressors (A,C,D,E,F,G,) with a total installed power at ISO conditions of 114.16 MW and one backup unit (B) with a rating of 19.91 MW. For cost allocation purposes Union bases the functionalization of investment carrying costs to transmission on the proportion of the total installed power that is required to raise the gas delivered at Dawn by TCPL and other cross-franchise shippers from the minimum receipt pressure of 700 psi to the pressure of 895 psi required for entry into the Dawn-Trafalgar System.

9.5.2 According to Union's methodology, which assumes that the total capacity is required for both storage and transmission services, 59.2% of the total test year carrying costs of $35.261 million is classified as transmission related and 40.8% as storage related.

9.5.3 TCPL's witnesses provided an alternative calculation which assumed that under peak design conditions, only part of the delivery capacity of compressors A and G (66,035 10^3m^3/day) was utilized to provide compression of cross franchise volumes (31,419 10^3m^3/day). The corresponding power requirement is 16.96 MW out of the total installed compression of 134.07 MW at the Dawn Station (including backup compressor B). This calculation results in a revised allocation of Dawn Compressor Station costs, 14.5 % to transmission and 85.5 % to storage. The result would be a cost shift of $7.035 million from ex-franchise transportation customers to storage customers.

9.5.4 Consumers' Gas provided evidence that its S&T contract with Union requires that volumes from the Tecumseh Gas storage pools also have to be delivered to the inlet of the Dawn Compressor Station at a minimum pressure of 700 psi and are then compressed to 895 psi for entry into the Dawn-Trafalgar System. Thus, the service provided to Consumers' Gas is identical to the service provided to cross-franchise transportation customers such as TCPL and Sithe Energies Inc. and accordingly, should be functionalized as transmission.

Positions of the Parties

9.5.5 Union argued that its allocation of Dawn Compressor Station investment carrying costs was appropriate since, if there were no storage facilities, Union would require compression facilities sufficient to raise the volume of all deliveries at Dawn to 895 psi. TCPL's proposal would also require a breakdown of the cost of each compressor unit and allocation to either transmission or storage whereas, in fact, all units are used interchangeably for both services. Union submitted that TCPL's calculations were based on a false premise and that Union's current methodology better reflects the realities and cost causality.

9.5.6 TCPL submitted that there is no rationale supporting Union's assumption that the power required for raising the pressure of storage gas from 700 psi to 895 psi is transmission related. In TCPL's view the allocation of Dawn Compressor Station carrying costs to transmission should be based on a factor of 14.5%. It also argued that Union's calculation of 59.2% is unsupported, is not based on cost causation and results in unjust and unreasonable M12 transportation rates. TCPL argued that the main purpose of the Dawn Compressor Station is to provide storage services; thus it is not part of the Dawn-Trafalgar System and therefore only a small percentage of the compressor power at Dawn is needed and used for transmission services during the Peak Design Day.

9.5.7 TCPL acknowledged that based on Consumers' Gas' evidence regarding the service provided to Tecumseh Gas Storage volumes, there is some basis for a treatment which is similar to that applied to volumes which arrive from the Great Lakes Pipeline, which require the same increase in pressure. If the Board concluded that those volumes are also transmission, instead of storage related, then TCPL calculated that the allocation factor for transmission would be 35.4%.

9.5.8 TCPL submitted that the Board should order Union to allocate 14.5% of Dawn Compressor Station carrying costs to transmission; alternatively, it argued that if the Board determines that Consumers' Gas' volumes are transmission related, 35.4% of the carrying costs should be allocated to transmission.

9.5.9 IGUA submitted that Union's methodology for allocating Dawn Compressor Station carrying costs better reflects realities and cost causality than TCPL's proposal. Any of the compressors can be used for transmission activity and are interchangeable, so that TCPL's analysis based on the assumption that only two compressors are used for transmission service is, as Union argued, a false premise.

9.5.10 Board Staff submitted that the allocation of Dawn Compressor Station investment carrying costs should be reviewed. The costs of the Dawn plant should reflect its use. If, as TCPL suggests, the compression required to raise gas from 700 psi to 895 psi is lower than the 59% of total compression currently allocated, it should be changed. Staff submitted that transmission customers should be allocated the cost of raising their gas to the outlet pressure and storage customers should be allocated the cost to withdraw their gas from storage and raise it to the outlet pressure on the Dawn-Trafalgar System.

Board Findings

9.5.11 The Board finds merit in TCPL's evidence and argument that the investment carrying costs of providing transmission related service at the Dawn Compressor Station are less than the 59% of the carrying costs of the Station which are currently allocated to this service by Union.

9.5.12 However the Board has an insufficient evidentiary basis upon which to find a more appropriate allocation, since TCPL's evidence supporting its proposed change to the allocation of compression costs, in the Board's view, is an incomplete analysis based on a challenged assumption that only part use of two compressors is required to provide transmission related service. This is not a criticism of TCPL's experts, but rather reflects deficiencies in the information upon which they had to rely.

9.5.13 The Board directs Union to examine this area more closely and in the next rates case, define in clear terms the exact design day compression services for storage and transmission services including those for Tecumseh Gas Storage, which it provides at Dawn, and to propose the appropriate adjustment to allocation of the associated carrying costs to each.

9.5.14 It appears to the Board that transmission compression service is relatively easy to define and cost, so it may be appropriate that once this is done, the balance of the installed compression costs should simply be allocated to storage compression service. The Board expects Union to allocate back up compression capacity to each service on a reasonable basis, such as the loss of one unit if specific units are allocated to each service, or alternatively proportioned to the compression requirement of each service.

9.5.15 For the purposes of setting 1997 test year rates the Board accepts Union's current allocation of Dawn Compressor Station investment carrying costs.

9.6 ALLOCATION FACTORS FOR DEMAND RELATED COSTS

9.6.1 Union's cost allocation is based on the aggregate contract demands of its M12 customers and the test year winter design day forecast peak demand of its in-franchise customers. The M12 customers are subject to overrun charges if their contract demand is exceeded whereas the in-franchise customers are not.

9.6.2 Consumers' Gas' witnesses disagreed with the different treatment of the design day peak demand for different customer classes and stated that a further concern is that Union is able to utilize the overruns of in-franchise customers to earn additional distribution margins. To correct this situation Consumers' Gas' witnesses proposed that a "ratchet provision" be applied to the in-franchise forecast peak demand. This would lock in the in-franchise demand based on a long-term forecast, in a similar manner to the way the M12 contract demand is derived. The provision should also apply to the forecast storage demand used for the allocation of storage costs.

Positions of the Parties

9.6.3 Consumers' Gas submitted that the different treatment of the two customer groups is unfair *per se*. Furthermore, it argued that the unfairness transcends the cost allocation process when overruns are taken into account. Consumers' Gas argued that its proposal for a "ratchet provision" applied to in-franchise design demand would introduce a much needed element of fairness, and at the same time would not impose overrun charges on in-franchise customers.

9.6.4 Board Staff, while subscribing to the case made by Consumers' Gas for equal treatment of in-franchise and ex-franchise customers, submitted that it is unclear from the evidence whether "there is a potential for a benefit to flow back to in-franchise customers because of the way Union is calculating the demand allocation factor. If Union is not properly reflecting its forecast of in-franchise demand and allowing its in-franchise customers to constantly overrun the system, then the factor should be changed." In Board Staff's view additional information and quantification of any benefit would be required before a change is made. There may be significant risks that the in-franchise customer assumes as a captive customer of the system.

9.6.5 Union, in reply, submitted that Consumers' Gas' analysis fails to recognize that in-franchise demand beyond design levels is supplied by additional east end deliveries and does not use Dawn-Trafalgar System transmission capacity. Consumers' Gas' proposal is also designed to ensure that if in-franchise demand goes below design levels there will be no increase in costs allocated to ex-franchise customers. Union submitted that this latter problem has not occurred and, no doubt should it do so, there would be further proceedings to determine the appropriate cost allocation and rate design responses.

Board Finding

9.6.6 The Board finds that there is an insufficient evidentiary basis to change the current allocation factors and, for the purposes of setting 1997 test year rates, accepts Union’s current approach.

9.7 ALLOCATION OF STORAGE REVENUES

9.7.1 Union's storage operations include 16 gas storage pools with a 1997 working capacity of 3.536 10^6m^3. Of this available space 2.198 10^6m^3 is used to meet in-franchise requirement and 1.338 10^6m^3 is contracted to ex-franchise customers.

9.7.2 Union also provides other services including both peak and off-peak storage services (gas loans, exchanges and parking) under the C1 rate.

9.7.3 For the 1997 test year Union's forecast of C1 Storage volumes and revenues was:

Peak Storage	560,894 10^3m^3; $3.974 million
Off-Peak Storage	1,071,468 10^3m^3; $1.898 million

Union allocates the forecast $5.872 million revenues from these services to the in-franchise customers.

9.7.4 Unforecast revenues from peak storage sales and exchanges are collected in the C1 Storage Revenue Deferral Account No. 179-39 for future disposition by the Board. This account captures revenue from the following services: C1 Peak Storage; C1 Firm short-term deliverability; and M12 Interruptible Storage Deliverability. There is no deferral account for unforecast off-peak storage.

9.7.5 Consumers' Gas disputed the allocation of C1 peak storage revenues to in-franchise customers only, on the basis that the total available storage space rather than just the in-franchise space makes such sales possible.

9.7.6 Union's evidence was that because M12 customers had contracted for a certain level of storage space, Union could not then sell off that space to the C1 peak storage market. With respect to off-peak storage, Union stated that M12 customers use their entire storage space and Union cannot therefore use that space to sell as off-peak storage.

9.7.7 Consumers' Gas' experts stated that in their opinion, unforecast C1 peak and off-peak storage revenues should be allocated to both in-franchise and ex-franchise storage customers since the latter pay for storage on the same basis as the in-franchise customers, and it is the total storage capacity which is used to generate the revenues. They pointed out that unforecast C1 transportation revenues are allocated to all customers. They also stated that apart from times when M12 storage space was full, it could be sold to the off-peak storage market.

Positions Of the Parties

9.7.8 All parties to the ADR Settlement Agreement, except Consumers' Gas, reached consensus that the disposition of the balance in the C1 Storage Revenue Deferral Account No. 179-39 should be based on a 90/10 split between in-franchise customers and the shareholder in both 1996 and 1997.

9.7.9 Consumers' Gas submitted that, with respect to forecast C1 off-peak storage revenue, the integrated nature of Union's storage system makes it impossible to determine the "ownership" of the unutilized storage between in-franchise and ex-franchise customers because "the gas is not colour coded". Accordingly the revenue should be shared in proportion to the storage space each group makes available, as is done with C1 transmission revenue.

9.7.10 Consumers' Gas also submitted with respect to peak storage, that all customers will pay the investment costs associated with the Bentpath/Rosedale (Storage) Project. The Project costs will be allocated 64/36 to in-franchise and ex-franchise customers respectively. This Project results in additional peak storage capacity, increased deliverability and reduced inventory requirements.

9.7.11 Consumers' Gas contended that Union should recognize the increased deliverability from Bentpath/Rosedale (Storage) Project in the allocation units. It disagreed with Union's position that not including this in the allocation units was appropriate, since there was no identified market for the deliverability.

9.7.12 Consumers' Gas argued that the unforecasted C1 peak storage revenues should be allocated in the same proportion as the costs of storage are allocated to in-franchise and ex-franchise customers. The M12 portion would be 37%, since this is the proportion of storage costs allocated to the M12 class.

9.7.13 Board Staff submitted that the allocation of C1 peak storage revenues by Union to in-franchise customers is correct. Board Staff accepted Union's position that it would be inappropriate to sell to the market storage space that it has contracted to M12 customers.

9.7.14 With respect to off-peak storage revenues, Board Staff agreed with Consumers' Gas' position. Every customer that starts to withdraw creates the opportunity for off-peak storage sales. Therefore, the forecast revenues should be allocated to all customers, including the M12 class, on the same basis as the C1 Margin Deferral Account No. 179-34, i.e. the level of available storage capacity on any given day as derived from the level of storage capacity contracted for and the forecast withdrawal pattern.

9.7.15 Union, in reply, submitted that based on the integrated nature of its storage system, it can provide off-peak storage as a result of its ability to control and manage gas supply requirements. Union's M12 customers also utilize storage services, but prediction of their withdrawal patterns in order to identify opportunities for off-peak storage services is not, in Union's view, practicable. Accordingly, Union submitted that all off-peak storage revenues should be allocated to in-franchise customers only.

Board Findings

9.7.16 The Board finds that the evidence in this case supports Union's methodology for allocation of forecast C1 peak storage revenues. The M12 customers would likely ask the Board for relief if Union sold any of their contracted peak space to a third party. In the Board's view, it is up to the party holding the peak storage contract to arrange with Union to market any available space. This would be strictly a commercial transaction subject to the Board's approved assignment procedures, with the net revenues to the account of the holder of the space.

9.7.17 With regard to the sale of off-peak storage, the Board finds there to be sufficient evidence that Union can utilize space contracted by M12 customers as their gas is withdrawn and therefore forecast revenues should be allocated prorata to <u>all</u> customers in the same way as the C1 Margin Deferral Account, that is based on the daily capacity available from in-franchise and ex-franchise customers. This would result in a reduction of $717,000 of the proposed allocation to in-franchise customers and a corresponding increase in the amount allocated to the M12 customers. This finding is predicated on Union's M12 storage customers cooperating with Union in the provision of advance notice of their withdrawal and injection patterns.

9.7.18 With respect to the disposition of the C1 Storage Revenue deferral account balance in 1996 for the test year, the Board accepts the proposed 90/10 split between the customers and the shareholder as agreed in the ADR Settlement Agreement for allocation of unforecast peak storage revenues. The 1997 balances will be disposed of in accordance with the Board's direction in the next rates case.

9.7.19 The Board finds that unforecast C1 off-peak storage revenues should also be captured in a separate C1 Off-Peak Storage Revenue deferral account effective January 1, 1997. These balances will be disposed of by the Board in the next rates case.

9.7.20 With respect to the Bentpath Rosedale (Storage) Project, the Board is of the view that, recognizing that the Project is to be completed late in the 1997 fiscal year and will then be allowed into Union's Rate Base as an asset considered to be used and useful, the functionality of that asset should be reflected in the cost allocation methodology. The Board therefore agrees with Consumers' Gas and finds that the allocation units for 1998 should reflect the increased deliverability generated from the Project.

9.8 ALLOCATION OF DISTRIBUTION CAPACITY COSTS

9.8.1 Union presented evidence in support of its proposal to change its cost allocation study with respect to distribution capacity costs.

9.8.2 Under Union’s current methodology, transmission capacity related costs are allocated to the various rate classes based on the peak demand of customers served from Union’s transmission facilities. Also, Distribution capacity related costs are allocated based on the peak demand of all customers, including those customers who are served directly from transmission facilities.

9.8.3 Union considers that customers served directly from transmission facilities do not require any distribution capacity to serve them, and hence proposed that they not be allocated part of the distribution capacity related costs of the system.

9.8.4 Union's evidence was that, following the proposed change, customer rates will still reflect the average cost to serve. Union pointed out that in the Board's Decision in E.B.R.O. 474-B/483/484 (Centra) the Board had accepted that the requirements of customers served directly from a transmission line exclusively through sole use main should be excluded from the demands used to determine the joint use main allocation factor.

9.8.5 The test year impact of the change as proposed and calculated by Union would represent an increase in Rate M2 cost allocation of $4,294,000 and a corresponding reduction in costs allocated to the large industrial rate classes, namely: $329,000, $819,000 and $3,146,000 to Rates M4/M5, M7, and T1/S1 respectively.

9.8.6 While parties to the ADR Settlement process did not agree on Union's proposed allocation of distribution capacity costs, Union's proposed change was unchallenged in the hearing.

Positions of the Parties

9.8.7 Union noted that, there would be no impact on 1997 rates as a result of its proposed change and that although the matter was not resolved in the ADR settlement process, the Company understood that there was no particular issue at this stage.

9.8.8 IGUA supported the Company's submission as well as those of Terra.

9.8.9 OCAP submitted that, viewed in isolation, Union's proposed change may seem appropriate, Methodologically it is defensible, but OCAP's concern was the direction of cumulative changes to Union's cost allocation study. This change would increase costs allocated to Rate M2 customers by $4,294,000.

9.8.10 In OCAP's view, judgement should be exercised based on the overall direction and cumulative impact. Each of the three cost allocation issues in this case affect residential customers directly and, in OCAP's view, the Company has a basic incentive to shift costs to Rate M2 customers because they are the most captive of the rate classes.

9.8.11 OCAP submitted that while Union may file sufficient evidence to back up its proposed changes, it does not file all the cost allocation data that parties would need to determine what other (offsetting) changes should be made.

9.8.12 OCAP recommended that the Board order Union to make its cost allocation model fully accessible to other parties in time for analysis before the next main rates proceeding. The fact that an independent review of the M12 portion of the study was undertaken serves to demonstrate that independent reviews may be both necessary and practical.

9.8.13 Terra noted that, notwithstanding the ADR Settlement Agreement on Terra's special by-pass rate, the Board had indicated that a Decision on the allocation of distribution capacity related costs could impact on Rate T1 and hence on the Agreement reached by the parties. Terra submitted that allocation of transmission capacity related costs should continue to be based on the total demand for the customers in each rate class. On the other hand, for distribution capacity related costs, total demand is not a good proxy for the actual use of distribution capacity. Accordingly, Terra supported Union's proposed change in cost allocation which in its view results in a better reflection of cost causality and changes revenue to cost ratios and not rates. Terra submitted that Union's change is appropriate and there is therefore no reason to modify the ADR Settlement Agreement with regard to the T1 Rates proposed by Union.

9.8.14 Board Staff supported Union's proposed change in allocation methodology for distribution capacity costs. In Board Staff's submission the change will result in alignment between customers who use the distribution facilities and those who are financially responsible for them. Union's proposal is appropriate from a cost causality perspective and in Board Staff's view, similar to Centra's proposal which the Board approved in its Decision in E.B.R.O. 474-B/483/484.

9.8.15 Union in reply noted that only OCAP had expressed concerns based on the impact on residential customers, and OCAP also recommended that the Board order the Company to make its cost allocation model accessible to it in time for the next rates case. Union submitted that giving intervenors access to the model is not an efficient approach to verifying the reasonableness of the cost allocation methodology. Costs are allocated to classes based on cost incurrence not in accordance with predetermined targets or objectives. Any concern about the ability of a class to recover the allocated cost of service, is more appropriately addressed in the rate design process.

9.8.16 Union submitted that the Board should approve the proposed change to the allocation of distribution capacity (costs) as it more appropriately reflects the cost responsibility of the rate classes.

Board Findings

9.8.17 The Board understands that, to the extent that rate classes have customers who are not served directly off the transmission system, the rate class will be responsible for some distribution capacity costs. To the extent that a rate class is predominantly served through transmission capacity, the Board is concerned that this allocation will result in an inappropriate level of avoidance of distribution capacity costs. This situation may arise should a rate class contain a small number of large customers with plants in remote areas which are serviced directly from transmission systems. The Board does not have adequate evidence to determine whether the cost shifts resulting from Union's proposal, particularly the significant cost shift from the T1/S1 rate classes, are appropriate, and consequently does not approve the proposed cost allocation change. In making this finding, the Board notes Union's statement that there are no rate impacts in 1997 as a result of this proposal.

9.8.18 For the above reasons the Board declines to approve the proposed change in cost allocation and the resultant shift in costs to the M2 class for the 1997 test year.

9.8.19 As noted in the hearing, the Board recognizes that its finding in this matter may in future affect Rate T1 and hence the ADR Settlement Agreement regarding the agreement by Terra "not to seek an extension of its special bypass rate in this proceeding".

9.9 M9 COST ALLOCATION: DISTRIBUTION SALES PROMOTION AND UNCOLLECTIBLE ACCOUNTS

9.9.1 Kitchener and NRG are LDCs and are the two M9 customers of Union. Their franchise areas are within the larger Union territory and are therefore bounded by Union.

9.9.2 Two issues were raised by Kitchener and NRG in the ADR settlement process - M9 cost allocation related to distribution sales promotion costs and to uncollectible accounts.

9.9.3 Union currently allocates a portion of its distribution sales promotion costs to the M9 rate class as well as to all other rate classes. The proposed total sales promotion cost is $36.522 million for 1997. This is broken down into customer related costs, and commodity related costs which are then directly assigned to rate classes based on the number of customers and forecast sales volumes. The M9 rate class is not assigned any customer related costs.

9.9.4 The commodity related distribution sales promotion costs proposed to be allocated to the M9 rate class in the test year amount to $89,000. Union's witnesses stated that this amount comprised approximately $36,000 for advertising, including media, newsprint, billboard and bill inserts, and $53,000 for staff related costs. According to Union, the objective of the sales promotion is to increase gas use, thereby benefitting all customers. The latest distribution sales promotion campaign included billboard advertising in the City of Kitchener.

9.9.5 Gas supply administration costs for 1997 were estimated by Union to be $1,533,527. Of this amount approximately $900,000 is related to uncollectible accounts. These costs occur as a result of in-franchise customers not paying their bills. The M9 rate class is assigned $58,680 of this cost.

Positions of the Parties

9.9.6 All parties to the ADR Settlement Agreement with the exception of Kitchener and NRG recommended acceptance of the Company's proposed allocation of distribution sales promotion costs and costs related to uncollectible accounts.

9.9.7 Union submitted that advertising costs should continue to be assigned to all customers served in its franchise area based on the benefit to all customers that results from increased sales volume. It noted that the only costs allocated to Kitchener and NRG are generic or institutional advertising costs that promote the use of gas in general. In recognition of the fact that wholesale customers do incur their own advertising costs, M9 customers are not allocated advertising costs which relate to the development of new business.

9.9.8 Kitchener submitted that the allocation of costs related to distribution sales promotion and uncollectible accounts to the M9 rate class is the result of a fundamental misconception at Union over the nature of the M9 rate class. Kitchener submitted that these costs are incurred in the service Union provides to its in-franchise customers. In the case of uncollectible accounts there is no cost incurrence due to the M9 rate class, who in fact have their own costs of this type associated with their own franchises.

9.9.9 Kitchener submitted that although the M9 rate class may receive an indirect benefit from Union's advertising, the same is true for Consumers' Gas which is not allocated any of the costs.

9.9.10 Kitchener argued that as a matter of principle it is not appropriate to allocate any of Union's distribution sales promotion costs to another utility.

9.9.11 NRG stated that it strongly objected to Union allocating any part of its distribution sales promotion costs to the M9 rate class noting that:

! Union was unable to substantiate its contention that the M9 rate class benefits from its sales promotion efforts over and above the efforts of the M9 utilities themselves;

- Union’s claim that M9 LDC's benefit by virtue of proximity to Union also applies to Consumers' Gas;

- increased volume may not benefit the M9 rate class since the impact could be to increase peak demand and associated demand charges;

- customers of Kitchener and NRG are being forced to pay twice for sales promotion efforts and in some cases Union’s promotions may be competitive with the LDC's own programs; and

- NRG is not an in-franchise customer of Union, but a geographically adjacent franchise as is Consumers' Gas’ Niagara region.

9.9.12 NRG argued that the Board should direct Union to remove the $36,000 in advertising costs and $53,000 in sales promotion supervision costs from the M9 cost allocation. NRG also submitted that Union should be directed to remove any sales promotion related costs from the $201,000 of direct assignment costs of the M9 rate class.

9.9.13 Union in reply submitted that the service provided to its M9 customers is generally the same as the service provided to other in-franchise customers and not, as alleged by Kitchener and NRG, equivalent to the M12 storage and transportation service. Rate M9 customers can purchase system gas supply and rely on Union to transport gas from Alberta to Ontario and to move gas in and out of storage. Rate M12 customers manage their own gas supply from the wellhead to their own distribution area.

9.9.14 Union argued that the characteristics of the service provided to M9 customers is, in all material respects, the same as that for in-franchise customers and accordingly, there is no reason why a share of the costs allocated to all other in-franchise customers should not be allocated to the M9 class as well.

Board Findings

9.9.15 The Board finds that as long as Kitchener and NRG take service under the provisions of the rate M9 class as currently defined, they should expect to receive their share of distribution sales promotion and uncollectible account related costs. However, the Board has some sympathy with the apparent desire of Kitchener and NRG to be treated more like storage and transportation customers, with regard to gas supply administration costs thereby narrowing the range of services they receive and reducing the associated cost allocation related to services such as sales promotion and bad debt protection that they do not cause or benefit from.

9.9.16 Accordingly, the Board directs the Companies to review the terms of the services provided to the M9 utilities in order to redefine these to be more in line with these customers' needs and to propose adjustments, as appropriate, to the cost allocation and rate design for rate M9 for the 1998 test year.

9.10 DIRECT ASSIGNMENT OF DSM COSTS

9.10.1 The Companies proposed to revise the assignment of DSM costs to the various rate classes in line with the new combined 1997 DSM Plan. The direct costs of the different programs are split between Centra and Union and then assigned to the rate classes for which the programs are designed and which are expected to benefit as a result. General overhead costs are assigned based on assigned direct program dollars.

9.10.2 The resulting proposed allocation for the 1997 test year is shown in Table 9.1.

Table 9.1: Direct Assignment of 1997 DSM Costs

DSM Program Costs $1000		**Union**			**Centra**				
Program	**Direct Cost**	**Total**	**M2**	**M7**	**Total**	**Rate 01**	**Rate 10**	**Rate 20**	**Rate 100**
New Home Construction	50	37.5	37.5	0	12.5	12.50	0	0	0
Home Equipment Replacement	580	435.0	435.0	0	145.0	145.00	0	0	0
Home Retrofit	465	349.0	349.0	0	116.0	116.00	0	0	0
New Building Construction	150	112.5	112.5	0	37.50	0	37.50	0	0
Bldg Equipment Replacement	300	225.0	225.0	0	75.00	75.00	0	0	0
Building Retrofit	350	262.5	262.5	0	87.50	87.50	0	0	0
Agriculture	50	50.0	50.0	0	0	0	0	0	0
Industrial Process Improvement	455	227.5	0	227.5	227.5	0	0	68.25	159.25
Total Program Costs	***2,400***	***1,699.0***	***1471.5***	***227.5***	***701.0***	***436.00***	***37.50***	***68.25***	***159.25***
Market Support	500	375.0	375.0	0	125.00	125.00	0	0	0
Research	300	187.5	112.5	75.0	112.5	18.75	18.75	22.50	52.50
Overhead Costs	500	353.4	306.1	47.3	146.6	90.60	8.80	14.20	33.00
TOTALS	**3,700**	**2,614.9**	**2,265.1**	**349.8**	**1,085.1**	**670.35**	**65.05**	**104.95**	**244.75**

Positions of the Parties

9.10.3 The following parties to the ADR Settlement Agreement agreed that Union's evidence on the allocation of test year DSM program costs should be accepted: Kitchener, Schools, NOVA, ONA, Board Staff, CAC, ECNG, NRG, IGUA, OCAP, Pollution Probe, GEC. CIPEC and IGUA reserved the right to examine and make submissions on the issue.

9.10.4 CIPEC submitted that if the (Board) panel were to strike down the industrial and commercial DSM programs and to disallow that portion of the 1997 DSM budget, then there should be no direct or indirect costs assigned to the industrial rate classes and the Board should then direct the Utilities to reallocate all of the DSM costs to the residential rate classes.

9.10.5 IGUA adopted and supported the submissions of CIPEC.

9.10.6 The Companies noted that the only parties examining on this issue were CIPEC and IGUA. The Companies submitted that there did not appear to be any outstanding issue with respect to DSM cost allocation for the test year.

Board Findings

9.10.7 The Board having approved the Companies' 1997 DSM Programs in Chapter 4 of this Decision, accepts the Companies' proposed assignment of DSM program costs to rate classes for the 1997 test year.

RATE DESIGN ISSUES

The following Union rate design matters were issues in the proceeding:

- Rate M2 Seasonalization;
- S&T Rate Design;
- R1 and T1 Services;
- Other S&T Services;
- Revenue to Cost Ratios; and
- S&T Services-Terms and Conditions.

The parties to the ADR Settlement Agreement did not reach a full consensus on any of these issues.

9.11 RATE M2 SEASONALIZATION

9.11.1 Union proposed to maintain its current non-seasonalized design for Rate M2 for the 1997 test year. Energy Probe and Pollution Probe continued their advocacy of seasonalized Rate M2 rates as in previous rates cases.

Positions of the Parties

9.11.2 The following parties to the ADR Settlement Agreement agreed with Union's proposal to maintain a non-seasonalized Rate M2 rate design for the test year: Kitchener, Schools, NOVA, Board Staff, CAC, CIPEC, Direct Energy, ECNG, NRG, IGUA, OCAP.

9.11.3 Energy Probe and Pollution Probe reserved their right to examine and to make submissions on this issue.

9.11.4 Union proposed to maintain the existing rate structure pending a review of rates following the proposed merger of the Companies and prior to the 1998 rate year. It submitted that there is no evidence in the current proceeding to support the seasonalization of rates.

9.11.5 Energy Probe submitted that, as a result of prior Board approvals, small volume general service customers of Centra and Consumers' Gas have seasonalized rates and there is no evidence that the differences with respect to Union are such that its Rate M2 customers would not benefit as well.

9.11.6 Energy Probe noted that the seasonal load factor for Union's Rate M2 customers has declined and this trend is forecast to continue in the test year. On the other hand Centra's load factor is steadily improving. Energy Probe disagreed with Union's witnesses who stated that there was no evidence that it cost less to serve the Rate M2 customers in summer. Energy Probe views seasonalized rates as a form of capacity or demand charge which is consistent with the rate design for larger volume customers. Energy Probe submitted that seasonalized rates would encourage customers to reduce peak consumption as well as provide additional incentives for customers to use gas for high load factor end uses such as water heating, cooking and clothes drying.

9.11.7 Energy Probe recommended that Union's Rate M2 should be harmonized with Centra's Rate 01 and that the Companies, in the next rates cases, should provide a study of the marginal costs of supplying firm customers and the full benefits of seasonalization of general service rates.

9.11.8 Pollution Probe submitted that seasonalizing Union's Rate M2 would make the rates more cost related, reduce Rate M2 customers' peak demands, encourage fuel switching from electricity to gas, improve Union's Rate M2 load factor and make Union's rate structure more consistent with those of Centra and Consumers' Gas.

9.11.9 For these reasons Pollution Probe submitted that the Board should encourage Union to seriously consider seasonalizing Rate M2 in 1998.

9.11.10 Union submitted that its evidence is that it wishes to maintain existing rates and plans to study the seasonalization of Rate M2 during its review of harmonizing general service rates following the proposed merger. It noted however that all of the necessary studies and analysis will not be completed in time for the 1998 rates case.

9.11.11 Union argued that there is currently no evidence that harmonizing Union's Rate M2 and Centra's Rate 01 as advocated by Energy Probe will provide any benefits.

Board Finding

9.11.12 The Board accepts Union's position that Rate M2 seasonalization should be examined as part of its review of rate harmonization following the proposed amalgamation of the Companies.

9.12 S&T RATE DESIGN

9.12.1 Union provides S&T service to ex-franchise customers under Rates M12 and C1. The current rate design includes range rates within which Union negotiates the rate for individual customers. Union proposed to expand the currently approved range to remove a pricing anomaly whereby limited firm transportation under Rate M12, which has a higher priority than interruptible service under Rate C1, may be priced below Rate C1. A further reason for the proposed change is that increasing the range would allow Union to negotiate prices which were closer to market at times when the market price exceeds the maximum of the current range, as was the case in the winter of 1995/96.

9.12.2 The proposed changes in the range rates are:

Table 9.2: C1 & M12 Range Rates

Rate/Service	Current Range 10^3m^3	Proposed Range 10^3m^3
M12 limited firm/interruptible transportation with compression. Easterly Flow	57.360-91.776	58.793-282.204
M12/C1 firm transportation without LCU protection. Easterly Flow	80.304-114.720	82.310-282.204
C1 Storage Space Deliverability	0.624-14.120	0.719-33.995

9.12.3 The proposed rate for limited firm/interruptible transportation represents 50-240% of the Rate M12 base rate and for firm transportation without LCU protection 70-240% of the Rate M12 base rate.

9.12.4 At the conclusion of the evidence stage of the hearing, the Board requested parties to address certain questions in argument, to assist it with its deliberations. One of these questions was " whether or not the Board has jurisdiction to approve range rates which reflect market conditions".

9.12.5 The Board has approved negotiated rates within ranges in the past, but given the extensive ranges proposed in the present Applications, the Board wished to review the question of its jurisdiction to approve range rates, and the practical implications.

Positions of the Parties

9.12.6 Union argued that its proposal should go forward in order to allow ratepayers and the Company to recover the value of the services provided. The Company argued that the Board has the jurisdiction to set range rates, and, in a competitive market, competitive prices would be "just and reasonable rates".

9.12.7 Board Staff supported the Company's proposal since, in its submission, it will resolve the existing rate anomaly and allow for a price which bears closer proximity to the open market price for similar services. The minimum of the range is above the average variable cost of providing the service. Board Staff also noted that Union has proposed that the balance in the C1 Margin Deferral Account be distributed 75% to the benefit of ratepayers and 25% to the shareholder, and submitted that the Company's proposal should be accepted.

9.12.8 Board Staff argued that the Board has the jurisdiction to impose range rates, noting that while range rates did present some possibilities for discrimination, they are used throughout North America and have previously been approved by the Board. The proposed bounds of the range rates in this case, the lower one based on marginal costs and the upper on the expected market price, are, in Board Staff's view, reasonable. The revenues generated will benefit customers, ensuring that the economic rents available from the provision of these services flow to the Companies and their customers, not to a secondary market.

9.12.9 IGUA submitted that the sale of services under range rates should never operate to the disadvantage of those customers whose demands for monopoly services have justified the construction of the facilities. When revenue from such services flows to the shareholder, this, in IGUA's view, creates the menacing potential that as long as the gas commodity merchant function remains under protection of the PGVA, the services will be oversold to the disadvantage of ratepayers.

9.12.10 IGUA submitted that range rates were appropriate to ensure existing facilities required for in-franchise needs were fully utilized, but that they should not be utilized where they would "permit utilities to include within the ambit of regulation the cost of acquiring incremental assets and facilities to provide goods or services to competitive markets at market prices". IGUA submitted that the Board ought to proceed cautiously before broadening the ranges for off-peak or curtailable services.

9.12.11 Consumers' Gas agreed with the Company, but stressed that the lower bound should be designed to recover the appropriate proportion of the LDC's revenue requirement. It also noted that market-related rates were appropriate only in a competitive market place, in which the service in question is provided by at least two parties.

9.12.12 ECNG endorsed the Company's view of the Board's jurisdiction, but argued that interruptible customers should not be subject to "coercive power" through interruptible contract terms and range rates to pay for gas cost increases for which they were not responsible.

9.12.13 No other parties commented on Union's specific proposals for expanded M12 and C1 range rates.

Board Finding

9.12.14 The Board is concerned that the non-competitive nature of the services may lead to detrimental impacts on customers. However, in the present circumstances, with a changing marketplace, long standing history of the use of range rates by the Utilities, and outdated legislation which may be interpreted in anomalous ways to serve the modern needs of a developing deregulated market, the Board is of the view that it should not restrict the Utilities' use of the proposed range rates, whatever a strict view of its jurisdiction might dictate. The Board therefore approves the proposed C1 and M12 range rates for the 1997 test year.

9.13 R1 AND T1 SERVICES

9.13.1 Currently Union's in-franchise customers can opt for either bundled delivery service, Rate R1, or for unbundled delivery service under Rate T1 which involves contracting separately for storage space, storage demand and transportation. Union proposed to supplement both the unbundled and traditional bundled services with "*optional*" services to be negotiated directly with the customer in order to provide a package of services customized to meet specific customer requirements.

9.13.2 The new services, if approved, would be similar to those currently offered to ex-franchise customers and would be incorporated in the existing Rate R1 and T1 rate schedules. Union stated that the new services have been developed as a result of customer feedback and a comparison with services available to customers in Centra's franchise area.

9.13.3 The proposed new services are:

- supplemental gas supply service;

- supplemental load balancing service; and
- optional T1 storage inventory demand charge.

9.13.4 Supplemental gas supply service is for customers who require Union to supply their incremental demand. Currently a customer who exceeds its contract demand is either charged the sales rate or curtailed, if interruptible. The actual cost of supplying the incremental gas results in debits or credits to the PGVA. Union now proposes to provide supplemental gas supply at its incremental cost plus a service charge of $\$5.00/10^3m^3$. The service charge is designed to encourage customers to arrange alternative supplies and not to rely on the Utility for backstopping. Union hopes to limit PGVA responsibility to system gas customers only.

9.13.5 Union indicated that supplemental gas supply service was similar to Centra's Rate 30 and would apply mainly to large volume industrial customers that were seeking backstopping, avoidance of curtailment or who required incremental supply for which they had not contracted. Union is not forecasting any revenue or cost from the service in 1997.

9.13.6 Supplemental load balancing service consists of short-term C1 storage and load balancing services for in-franchise customers. At present these services are only available to ex-franchise customers so that a customer in Centra's franchise can obtain the services but Union's in-franchise customers cannot. Load balancing services include gas loans, gas parking, off-peak storage as well as additional peak storage which is subject to the storage queue. Prices for these services would be negotiated within the C1 range and subject to prevailing market prices.

9.13.7 The T1 Storage Inventory Demand Charge relates to the provision of storage deliverability service for which Union carries gas in inventory to meet demand on peak day. The cost of this inventory is included in the T1 storage and withdrawal demand charge. Union proposes to allow customers the option of carrying their own inventory and to discount the rate to reflect Union's avoided costs. The parties to the ADR Settlement Agreement agreed that Union's proposal on this matter should be accepted.

Positions of the Parties

9.13.8 Union submitted that extending the proposed services to in-franchise customers provides them with access to facilities now available to ABM's and ex-franchise customers.

9.13.9 Board Staff noted the concerns of other parties about the supplemental gas supply service based on the recent experience with Centra's Rate 30 and the fact that it appeared to some to be a competitive instrument against gas marketers. Board Staff expressed concern that, while the service is intended for backstopping, the proposed R1 and T1 Rate schedules do not set out any restrictions relating to the use of the service unlike those in the Centra Rate 30 schedule.

9.13.10 While supporting the concept of a backstopping service, Board Staff submitted that the supplemental gas supply service as proposed is too broad, as it would permit Union to supply 100% of a customer's demand. Given the ongoing 10-Year Market Review and the current reliance on LDCs as facilitators of the direct purchase market it would be inappropriate to allow an LDC to offer gas supply at other than the Board approved WACOG.

9.13.11 Board Staff submitted that the proposed R1 and T1 rate schedules should be amended to incorporate much more restrictive eligibility requirements, such as are in place for Centra's Rate 30. This would ensure the service is only available on an incremental and intermittent basis to supply customers during periods of interruption of their gas supply.

9.13.12 Board Staff also submitted that the basis for the $5.00 fee has not been established and Union should be required to book any fees related to the supplemental gas supply service in the PGVA to avoid any incentive to promote the service.

9.13.13 With regard to the proposed supplemental load balancing service Board Staff noted that the Company saw this as a way of mitigating any impact of the proposed two point balancing proposal, but expressed concern about the negotiated rates and the potential for unforecast revenues to the Utility. On balance Staff supported the proposal because it saw the necessity of a service to permit load balancing by direct purchase customers which at present is only available to ex-franchise customers.

9.13.14 ECNG stated that it was opposed to the proposed R1 and T1 services because a regulated utility should not be allowed to sell gas at market-based rates. ECNG viewed the proposed supplementary gas supply service rate as akin to a Retail Competitive Offering in that the rate lacks explicit restrictions as to how and when it will be used. The proposed R1 rate would be very different from the existing Centra Rate 30 as it could be used by any class of customer, firm or interruptible, for any period of time and would lead in ECNG's view, to streaming of the gas supply.

9.13.15 ECNG submitted that the proposed supplementary load balancing service is tied to the two point balancing proposal which it opposed and would therefore be unnecessary should the Board not approve that proposal. ECNG submitted that even if two point balancing were approved, a market based rate should not be approved.

9.13.16 ECNG submitted that Union’s proposal to sell short-term storage under the T1 storage inventory demand charge proposal at market based rates is contrary to the Board’s Decision in E.B.R.O. 486-02 and introduces the concept of market based rates for in-franchise storage. ECNG argued that such matters should be considered in a generic proceeding.

9.13.17 ENRON submitted that the Board should not approve the proposed supplemental gas supply service since it is a competitive supply option and is inconsistent with the role of Union as a facilitator of the direct purchase market. In addition, in ENRON’s view, negotiated rates are inconsistent with the standard of “just and reasonable” within the meaning of section 19(1) of the Act.

9.13.18 IGUA supported the availability of supplemental gas supply service subject to the language in the rate schedule being revised to bring it in line with Centra's Rate 30 and the removal of the $5.00 service fee. In IGUA’s view, Union should not make a profit from the sale of gas as long as the functions carried out by the LDC remain under the ambit of regulation and any non-cost-based surcharge ought therefore to be disallowed.

9.13.19 IGUA submitted that the range rate for the supplemental load balancing service ought to be far narrower until experience is gained with the service and suggested a fixed charge of no more than $\$5.00/10^3m^3$ with revenues to be recorded in a deferral account for subsequent credit primarily to customers.

9.13.20 IGUA noted the proposal, under the proposed T1 Storage inventory demand charge, to offer short-term storage/load balancing available under the R1 and T1 rate schedules and requested Union clarify in its Reply Argument the difference between this and the supplemental load balancing service proposed under the C1 storage rate.

9.13.21 The Universities expressed concern that the proposed supplemental gas supply service would result in streaming. However, since the service provides another option to avoid interruption and it is at the discretion of the customer, the Universities were prepared to accept the proposal for the purposes of this proceeding. The Universities submitted that if the Board approves the two point balancing proposal, it should approve the supplemental gas supply service and vice versa.

9.13.22 The Universities submitted that the Board should approve the proposed supplemental load balancing service since Centra and Union were operating under Shared Services and accordingly their customers should have access to the same services.

9.13.23 Union in reply submitted that it was not the intent that the supplemental gas supply service would be offered as a different service to that currently available to Centra's customers. The fee of $\$5.00/10^3m^3$ was designed to ensure prices were above market and ensure that other gas supply options would be competitive, as well as deter reliance on the Utility. It is Union's position that the proposed service would provide customers with a reasonable option to backstop direct purchase supplies while balancing the concerns of the direct purchase suppliers regarding competition from the Utility.

9.13.24 With regard to the supplemental load balancing service, it was Union's aim to extend services currently provided to ex-franchise customers under rate C1 to in-franchise customers under rates R1 and T1. Union noted IGUA's concern about the proposed range rate and suggested that IGUA's objection was based on a misunderstanding of the scope of the range, since the minimum charge recovers the marginal cost and the maximum will capture the market value of the service. Accordingly Union argued that the rate should be approved.

9.14 OTHER S&T SERVICES

Ex-franchise Gas Supply Service

9.14.1 Union proposed to offer a supplemental gas supply service to its ex-franchise customers. The service would be similar in nature to the new R1 and T1 services, in that it would involve negotiated prices for gas supplies. Union's witness indicated that this was being offered in response to requests from customers for a backstopping service. Union indicated that at present this type of service was provided to the customer through ex-Ontario transactions.

9.14.2 Board Staff took issue with the offering of this service on the basis that ex-franchise customers are all LDCs or other large volume users of natural gas, and that these customers purchase all of their supplies in the market. Staff suggested that while these customers may desire the option there was no reason they could not purchase supplies on their own behalf from market participants.

9.14.3 ENRON submitted that a negotiated rate for gas supply was inconsistent with the role of the LDC as a facilitator of the direct purchase market. Further the offering of gas supplies at negotiated rates produces risks of cross-subsidization and unfair competition. It also relied on the ongoing review of the market structure and that Union should not be offering new competitive supply options at this time.

9.14.4 Union in reply stated that gas supply services to ex-franchise customers had been previously done through transactions outside Ontario. Union stated that the service is supplemental and the possibility of cross-subsidization is not based on any evidence in this hearing.

Other S&T Services

9.14.5 Under the heading Services Not Subject to Deferral Account Treatment, Union filed evidence on 1997 off-peak storage contracts, gas loans, balancing, redirections/name changes and hub to hub service. The Board has reviewed the off-peak storage service earlier in this Chapter.

9.14.6 The Company's evidence was that *gas loans* are a service under which Union lends gas to a customer who needs gas and subsequently repays the loan with an equivalent volume at a later point in time. For 1997 Union forecast loans of 607,941 10^3 m^3 and revenue of $3.5 million, compared to 591,710 10^3 m^3 and $3.75 million in 1996.

9.14.7 *Balancing service* is a combination of off-peak storage (parking) and loans. The service operates similar to a bank account with a line of credit attached. If the customer has used gas the account is in a negative balance using the line of credit and if the customer supplies gas the account is in a positive balance. The 1997 forecast revenues from this service are included in the off-peak storage and gas loan revenues above.

9.14.8 *Redirections/name changes* are commonly referred to as "meter bounces". Union uses these services to provide transfers of gas between contracts or title transfers between customers who wish to exchange gas. Redirected gas never enters Union's system but is required to meet a shipper's upstream or down-stream requirements. Name changes occur when gas owned and redelivered to one party enters Union's system under the account and title of a different party who holds the transportation on Union's system. Union proposed a fee of $0.35/$10^3m^3$ for redirections as in 1996 and a new fee of $0.088/$10^3m^3$ for name changes. The forecast name change volumes are 2,878,922 10^3m^3 and revenues of $253,345 for 1997.

9.14.9 Under Union's *hub to hub* service a customer delivers gas to the Alberta Energy Corporation hub in Alberta and receives an equivalent volume of gas at Dawn. Thus the service is an alternative to traditional transportation from Alberta to Ontario. The fees charged for this service and other details are confidential and the forecast revenues are rolled in with the revenue forecasts for off-peak storage and gas loans.

ADR Settlement Agreement

9.14.10 The parties to the ADR Settlement Agreement approved Union's Other S&T Services with the exception of Consumers' Gas regarding off-peak storage, which is the subject of an earlier Board finding.

Board Findings

Supplemental Gas Supply Service

9.14.11 The Board finds that the proposed supplemental gas supply service has not been adequately justified based on customer need, nor has the proposed fee of $5.00/10^{3}m^3$ been adequately explained. For these reasons, and given the Board's finding on the Company's proposed two point load balancing for the test year, the Board declines to approve the proposed supplemental gas supply service.

Supplemental Load Balancing Service

9.14.12 The Board finds that although there is no strong evidence of a ground swell of customer requests, this service can be justified primarily on the basis of equal treatment of in-franchise and ex-franchise customers, especially in light of the proposed merger of Union and Centra.

9.14.13 Accordingly the Board approves the proposed supplemental load balancing service, subject to the eligibility and terms of service set out in the amended R1 and T1 rate schedules filed in this proceeding. Any 1997 revenues should be captured in the C1 and M12 Storage Net Revenue Deferral Account No. 179-39.

T1 Storage Inventory Demand Charge

9.14.14 The Board accepts Union's proposal to allow customers to provide their own inventory and to charge only the T1 Storage Inventory Demand Charge. Any 1997 revenues should be captured in the C1 and M12 Storage Net Revenue Deferral Account No. 179-39.

Ex-franchise Gas Supply Service

9.14.15 The Board has insufficient information to approve this service.

Other S&T Services

9.14.16 The Board notes the acceptance of these services and forecast revenues for 1997 by the parties to the ADR Settlement Agreement, however the Board has concerns about the following aspects of these services: the fact that parties to the hearing questioned the level of fees particularly for "meter bounces", even though these were not part of Board-approved rates; the lack of information underpinning the forecast revenues; and the fact that the Board has no information on hub to hub transactions or the associated costs and revenues.

9.14.17 For these reasons the Board directs Union to capture the difference between forecast and actual revenues from these Other S&T services in a variance account and to provide adequate information for the Board to determine the appropriate disposition of the balances in the next rates case.

9.15 REVENUE TO COST RATIOS

9.15.1 Union's evidence was that its proposed rates for 1997 will recover the total cost of service and that in its rate design it had considered the costs allocated to each rate class as well as the current level of rates. The proposed 1997 rates result in revenue to cost ratios consistent with prior years and there are no significant changes in relationships.

9.15.2 Kitchener and NRG questioned Union's witnesses on the M9 revenue to cost ratio which had changed from 1.0062 approved by the Board for 1995 to 1.001 with a revenue excess of $28,000 for 1997.

Positions of the Parties

9.15.3 Union, noting that Kitchener had cross-examined on this matter, submitted that since the M9 revenue to cost ratio was close to one it should not be of any concern to the Board.

9.15.4 Kitchener noted the repeated directions of the Board requiring Union to effect a rate design which achieves revenue to cost ratios of one for each rate class and submitted that these directives were particularly important for other LDCs served by Union because their customers should not be asked to subsidize services to Union's in-franchise customers.

9.15.5 However, in this case, Kitchener accepted that the M9 revenue to cost ratio for 1997 is so close to one as to be cost based. Accordingly, Kitchener did not seek any alteration of the M9 rate.

9.15.6 NRG submitted that comparisons of revenue to cost ratios that include gas supply costs and revenues are not a sufficient measure of the appropriateness of the proposed rates and that Union should be directed to file revenue to cost ratios split between the supply and delivery components.

9.15.7 NRG indicated it was pleased that Union had reduced the M9 revenue excess from $187,000 to $28,000, but submitted that Union should be directed to eliminate this excess entirely, since it is inappropriate that NRG's customers continue to indirectly subsidize Union's customers by paying charges that are higher than are required by Union to earn its allowed rate of return.

9.15.8 Board Staff, CAC, and IGUA all accepted the revenue to cost ratios that result from the proposed 1997 rates. IGUA submitted that Union should be directed to also file evidence on delivery related revenue to cost ratios in the next rate case.

9.15.9 Union in reply noted the position of the other parties and submitted that the Board should reject NRG's proposal to reduce the forecast revenue by one tenth of a percent to make the M9 revenue to cost ratio exactly equal one, since allocated costs should be viewed as a reasonable indication of cost responsibility and not the precise cost to serve. Union stated that it would take into account the suggestions made by certain parties on information to be filed in the next rates case and that a Board directive was not necessary.

Board Finding

9.15.10 The Board finds that Union's revenue to cost ratios as filed in its updated evidence at the end of the oral hearing, are appropriate as a base for the determination of 1997 test year rates.

9.15.11 The Board directs Union to make the adjustments to cost allocation resulting from its Findings regarding the 1997 cost of service and specific cost allocation issues. To the extent that the Company's proposed cost allocation changes were not reflected in the Company's proposed 1997 rates, and these changes were approved by the Board, the Board understands that the Company will not reflect these cost allocation changes in 1997 rates.

9.16 S&T SERVICES - TERMS AND CONDITIONS

9.16.1 Two issues were addressed under this topic:

- First Right of Refusal - C1 & M12 contracts; and
- Off-Peak Storage - Blanket Approval.

First Right of Refusal - C1 & M12 Contracts

9.16.2 Union proposes to change the terms and conditions of C1 and M12 contracts in regard to first right of refusal/assignments.

9.16.3 Union has contractual arrangements for transportation services with a number of ex-franchise customers including Consumers' Gas.

9.16.4 Consumers' Gas disagreed with certain provisions related to partial or full assignments of its contracted transportation capacity. Specifically, Consumers' Gas disagreed with the notice period and Union's exercise of its first right of refusal. In the ADR

Settlement Agreement the parties agreed to a 350 day recallable assignment provision and a reduction in Union's time to exercise its first right of refusal for partial assignments from five business days to two business days.

9.16.5 In the hearing, Union filed a letter to Consumers' Gas dated December 21, 1994, in which it had offered to restrict the first right of refusal provision to circumstances where there is a risk of failure of non facilities related capacity on Union's system such as TCPL WPS or deliveries to the east end of the Dawn-Trafalgar System.

9.16.6 The Company also filed a copy of the latest Letter Agreement dated October 10, 1996, which superseded a previous 1993 agreement on call back rights by Consumers' Gas. Under the terms of the October letter, the parties agreed to Consumers' Gas assigning a portion of its M12 contract demand to Union, subject to a 12 month minimum term and a Consumers' Gas call back provision for up to 15 days service upon 24 hours notice. The Letter noted that the Agreement would not be deemed as a precedent or basis for attempting to limit or obtain further assignment rights.

Positions of the Parties

9.16.7 Union submitted that its position was reasonable and to the extent that there are matters outstanding between Consumers' Gas and Union in this rather arcane area they should be left to the parties to resolve. Union expressed the view that the parties are making progress in this regard.

9.16.8 Consumers' Gas submitted that Union's first right of refusal is an issue in this case because Union takes the position that it is of general application for all Rate M12 and C1 partial assignments. This, in Consumers' Gas' view, means that Union also claims a first right of refusal on partial assignments under contracts that do not contain a first right of refusal provision.

9.16.9 Consumers' Gas submitted that, for this reason, the issue is <u>not</u> a matter of a contractual dispute between Consumers' Gas and Union, but rather whether the Rate M12 and C1 schedules should contain a first right of refusal provision of general application and, if so, should the scope be as Union proposes.

9.16.10 In Consumers' Gas’ view a conventional first right of refusal allows Union to acquire a shipper’s contracted M12 or C1 transportation capacity at a price below the value that capacity might otherwise have. Consumers' Gas submitted that the very existence of a conventional first right of refusal has negative implications for a shipper’s ability to put assignment related transactions in place in today’s market conditions.

9.16.11 In Consumers' Gas’ view the situation is exacerbated by Union's claim to an unconventional first right of refusal i.e. Union could claim only a portion of the capacity for part of the term of the proposed assignment. As a consequence, a shipper may not be kept economically whole by the transaction and, in the extreme, Union could scuttle a long-term partial assignment by using its rights to claim a small portion of the capacity for a short period.

9.16.12 Consumers' Gas submitted that the first right of refusal places the responsibility for Union's failure to manage non-facilities related capacity upon the ex-franchise shipper who has the misfortune to be making an assignment when the failure occurs. In Consumers' Gas' view, this is unfair and the cost should be borne by all in-franchise and ex-franchise users of the system.

9.16.13 Consumers' Gas argued that the Board should rescind Union’s first right of refusal as one of the partial assignment rules approved in the E.B.R.O. 462 and 470 Decisions. If the Board declines to do this, then, as a minimum, it should deny Union’s unconventional first right of refusal as a rule of general application.

9.16.14 In reply Union's position was that it should retain the right of first refusal for all assignments of transportation capacity. This would insure against the risk of a transportation capacity shortfall. However, Union submitted that it would be willing to work with customers to accommodate their requests for assignments.

Board Findings

9.16.15 The Board finds Union’s “conventional” first right of refusal as set out in the Rate M12 and C1 schedules and general conditions of service to be appropriate for the test year. The original reasons related to using available capacity for in-franchise service, which were accepted by the Board in its E.B.R.O. 462 and 470 Decisions are still relevant as long as Union is the shipper for its in-franchise customers.

9.16.16 However, the Board believes that the "unconventional" first right of refusal has the potential to be economically disadvantageous, because of lost opportunity cost, to Union's long-term M12 and C1 shippers whose contracted demand has also underpinned the S&T Assets on the Dawn-Trafalgar System.

9.16.17 The Board directs Union to operate in accordance with the rate schedules and general terms of service provisions and a "conventional" first right of refusal whereby in general, Union would "step into the shoes of the assignee" and assume responsibility for the total assigned capacity for the whole period of the assignment. It should then seek to assign any unrequired capacity to mitigate the costs to in-franchise customers. However, it could be appropriate for Union and the shipper to agree to commercial terms involving other partial or temporary assignment provisions, if this also reduces the exposure of the in-franchise customers to unabsorbed demand charges.

Off-Peak Storage - Blanket Approval

9.16.18 Union requested that the Board vary its E.B.O. 166 Order which established a blanket approval process for short-term storage contracts. E.B.O. 166 provides for blanket approval of all storage contracts which are for less than one year in length and less than 56,600 10^3m^3 (2 Bcf) in volume. Union requested a blanket approval to enter into longer-term (up to 15 years) off-peak storage contracts with an increase in the ceiling on volumes of up to 141,500 10^3m^3 (5 Bcf). Union stated that the reason for the request is that customers are looking for more flexibility in storage services.

9.16.19 The Companies identified storage as one of the regulated activities they foresee as being deregulated and open for competition.

9.16.20 In Union's view, given that there are no constraints on the volume of off-peak storage, increasing the volume limit to 141,500 10^3m^3 (5 bcf) would not limit the availability of the service to other customers, since at present the Company can accept all requests.

9.16.21 Union noted that the Board in its E.B.O. 192 and 199 Orders has previously approved two off-peak storage applications that involved volumes greater than 2 Bcf. The Board has also granted Consumers' Gas blanket approval of off-peak contracts for one year terms with no limitation on the contract volumes (E.B.O. 190 Order).

9.16.22 With respect to the request to extend the blanket approval to contracts with terms of greater than one year and up to 15 years, Union explained that the change to a longer-term would relieve an administrative burden on the customers associated with contract renewals.

Positions of the Parties

9.16.23 Board Staff accepted that Union currently has no constraint on the amount of off-peak storage it can offer because of the large amount of gas which is withdrawn from storage commencing in November each year. Therefore, in Staff's submission, changes to the blanket approval under E.B.O. 166 were appropriate and the cap on individual off-peak contracts should be lifted to 5 Bcf as requested.

9.16.24 With respect to the lengthening of the term of off-peak contracts, Board Staff submitted that the Company had not made a proper case for this change.

9.16.25 Board Staff expressed concern that longer-term off-peak contracts may be more difficult to keep track of and to alter should operating circumstances change significantly. In Board Staff's view, entering into long-term contracts when deregulation of storage is being contemplated may prove to be unfair to customers.

9.16.26 Union, in reply, submitted that the proposed 15 year contract term is required for customer convenience and administrative efficiency and will not adversely affect any other customer group, since off-peak storage services are provided only on a reasonable efforts basis.

Board Finding

9.16.27 The Board finds that the Company has not adequately justified a blanket change to the E.B.O. 166 provisions on the basis of customer need and cost savings. There are also significant uncertainties whether or not S&T Services will be separated and/or deregulated. For these reasons the Board finds it is inappropriate to extend either the volume or term provisions of E.B.O. 166 on a blanket basis at this time. The Company can apply for extensions on a specific basis as at present.

10. CENTRA COST ALLOCATION AND RATE DESIGN

COST ALLOCATION METHODOLOGY

10.0.1 Centra proposed a number of changes in cost allocation for the 1997 test year. The Company indicated that the proposed changes generally arose from intervenor concerns and/or Board directives in prior rate cases. These changes were:

- Allocation of joint use mains and demand costs for grid mains;
- Allocation of customer accounting costs; and
- Allocation of bad debt expense.

None of these issues was resolved in the ADR settlement process.

10.0.2 The direct assignment of the Companies' combined 1997 DSM costs has been addressed in Union's Cost Allocation and Rate Design in Chapter 9.

10.0.3 Centra's Cascade methodology was agreed to in the ADR Settlement Agreement subject to review in 1998. Centra's gas supply administration costs were also agreed to in the ADR Settlement Agreement. The Board accepts these agreements.

10.1 ALLOCATION OF JOINT USE MAINS AND DEMAND COSTS FOR GRID MAINS

10.1.1 Centra's mains are classified into three categories for cost allocation purposes:

- Sole use - serving a single end user,
- Joint use - serving different customers in different rate classes
- Grid - serving predominantly residential and small commercial customers.

10.1.2 In its Decision in E.B.R.O. 489 Part I the Board directed Centra “to review the ways, and associated costs by which its current system method of allocation of joint use mains can be validated." In its review "Centra should also include the option of ascertaining the relationship between a lateral-by-lateral peak demand allocator and a system wide peak demand allocator". The Board stated Centra should report to the Board at its next main rates case.

10.1.3 In responding to the Board’s directive, Centra’s evidence was that the use of system peak and average as a proxy for a lateral-by-lateral peak demand allocation factor was previously adopted by Centra and approved by the Board in its E.B.R.O. 399 Decision because this methodology:

- eliminated the costly and time consuming exercise of maintaining lateral specific plant costing information;
- eliminated the cost, effort and deficiencies associated with maintaining lateral specific daily demand information; and
- produced results essentially equal to a lateral-by-lateral peak allocation factor approach.

10.1.4 Centra estimated that it would take a year of staff effort and cost $62,000 plus support from existing staff in other departments to update the lateral-by-lateral ("Segplant") study to test the reasonableness of the system peak and average allocation factor as a proxy for a lateral-by-lateral peak allocation factor.

10.1.5 A second alternative which Centra considered was analyzing a sample of laterals to test the reasonableness of the system peak and average allocation factor as a proxy for a lateral-by-lateral peak allocation factor. The Company concluded that this approach would not be significantly less work than updating the entire study.

10.1.6 The third alternative that Centra considered was to propose a different allocation methodology - the allocation of joint use main costs on the basis of system wide peak day demand (allocation factor #35) which, in Centra's view, appropriately reflects the manner in which these costs have been incurred. Centra proposed this as the most appropriate alternative for the 1997 test year and noted that this methodology had the added advantage of being similar to that used by Union. If accepted, this change in methodology would allocate $3,024,000, $795,000, $218,000 and $500,000 more costs to Rates 01, 10, 16 and 25 respectively and $517,0000 and $4,020,000 less costs to Rates 20 and 100.

10.1.7 Centra also proposed to allocate the demand component of grid distribution mains based on system wide peak demand excluding large industrial volumes (allocation factor #37) rather than system wide peak and average as at present. This change would have the impact of allocating $509,000 of additional costs to Rate 01, and an additional $248,000 to interruptible rate class 16, with an offsetting reduction of $757,000 to Rate 10.

Positions of the Parties

10.1.8 OCAP, CAC and Board Staff challenged Centra's proposed change to system wide peak allocation factors for the allocation of the costs of joint use mains.

10.1.9 Centra submitted that it would be extremely costly and time consuming to validate the use of the system peak and average as a proxy for a lateral-by-lateral peak demand allocation factor. In Centra's view the benefit of such a study would not be realized by customers as it is unlikely to result in any change to the proposed rates.

10.1.10 CAC submitted that Centra did not present in evidence any studies to support the proposed change in cost allocation methodology. CAC also noted Centra's admission that there may not have been significant changes to its system since the last rates case to indicate a change in methodology is required. CAC argued that the existing methodology should be maintained until there is compelling evidence to support the use of the system peak day allocation factor in allocating the cost of joint use mains.

10.1.11 OCAP submitted that the two key questions are whether there is evidence that system peak and average is no longer the best practical method and whether the Segplant study should be updated. In OCAP's view Centra failed to present any justification for changing from peak and average to system peak. The cost of updating the Segplant study does not offset the $3.5 million the residential class would face if Centra's proposal were accepted. OCAP argued that no change should be made in the absence of evidence that it is appropriate.

10.1.12 IGUA supported Centra's proposal to use system peak as the allocation factor for the costs of joint use mains. It submitted that it is the peak day demands on each lateral which drives the incurrence of joint use mains costs. In IGUA's view, the system peak is a reasonable surrogate for a lateral-by-lateral approach since it incorporates peak demand which drives costs in the design of Centra's system, while excluding annual volume which does not.

10.1.13 Board Staff expressed concern with Centra's proposal to use system peak demand as the allocation factor for joint use mains and indicated that it found it difficult to reconcile a new allocation methodology in light of Centra's defence of the system peak and average allocation factor for the costs of joint use mains in E.B.R.O. 489.

10.1.14 Board Staff submitted that Centra should continue to use the system peak and average methodology for the allocation of the costs of joint use mains for the following reasons:

! Centra's witnesses agreed during cross-examination that Centra's physical system is different to Union's, so that using the same methodology mainly for consistency with Union is inappropriate;

! Centra failed to provide any evidence or recent studies to refute the Company's evidence and conclusions presented in E.B.R.O. 489; and

- the new witnesses now responsible for this area following the Shared Services arrangement acknowledged that Centra's witnesses in E.B.R.O. 489 had more familiarity with the Centra system.

10.1.15 Board Staff argued that Centra should continue to use the system peak and average allocation factor for the cost of joint use mains until the Company clears the record by undertaking the necessary studies, which in its view, would cost less than any of the resulting rate impacts. Board Staff submitted that if the Company believes the study is too expensive, it should bring forward an outline and anticipated costs in the next rates case. Should the Company decide not to do this, the current methodology of system peak and average should continue.

10.1.16 Centra in Reply Argument submitted that the work involved in updating the Segplant study would be very onerous and the time and cost associated with it would not be justifiable. Centra estimated that it would take 6 person years to update the original study that justified the use of system peak and average as a proxy for an analysis of costs on each of the approximately 110 laterals. In Centra's view there is no apparent principle to explain why system peak and average correlated with the original Segplant study, and since the completion of the study in 1981, laterals have been added and depreciated and the demands of customers have changed. For these reasons Centra's proposal to allocate the costs of joint use mains on the basis of system peak demand would result in an allocation of costs which would better reflect design and cost incurrence.

Board Findings

10.1.17 The Board believes that there is evidence on the public record to indicate that the characteristics of joint use mains in the Union and Centra systems are sufficiently different that the same cost allocator may not be appropriate for both systems. Union's joint use mains are part of a grid network and so the use of system peak may be quite justified. Centra's joint use mains are "spines" from the transmission pipeline and that 16 years ago, the use of system peak and average provided a close match to a lateral by lateral peak approach to cost allocation.

10.1.18 The Board finds that Centra has not provided convincing evidence in this proceeding to support the change to the system peak allocator (factor #35) from the current system wide peak and average for the allocation of the cost of joint use mains. The Board directs Centra to retain the use of the current system wide peak and average for the 1997 test year, pending the filing of evidence that substantiates a new allocation factor in the next or future rates case.

10.1.19 The Board notes that one of the Company's justifications for its proposal to change the allocation of the demand component of grid distribution mains was consistency with the treatment of joint use mains. The Board does not approve the proposed change given its finding above. The Board observes that if the Company wishes to bring forward a similar proposal in a future proceeding the Board will also require evidence to explain how the change to peak demand allocation factor results in a higher allocation of costs to an interruptible class of customers.

10.2 ALLOCATION OF CUSTOMER ACCOUNTING COSTS

10.2.1 Centra allocates forecast customer accounting costs based on a weighted customer number allocation factor.

10.2.2 With regard to customer accounting costs, the customer weightings approved in E.B.R.O. 483/484 were:

- Rate 01 1
- Rates 10, 16 5
- Rates 20, 25, 100 10

10.2.3 In its Decision in E.B.R.O. 489 the Board derived an interim allocation for the 1995 test year based on percentage allocation factors and also directed Centra to undertake time docketing of its customer accounting function to assess the reasonableness of the weighted customer number cost allocation factors. Centra did this study for a period of three months and based on the results, concluded that the customer weightings used to derive the allocation factors in E.B.R.O. 483/484 were still appropriate.

Positions of the Parties

10.2.4 Centra submitted that the results of the study validated the current use of customer weighting and allocation factors and the use of weighting does not require the same level of administrative effort that is involved in maintaining time sheets. Centra noted its understanding that CAC and OCAP persist in the belief that time docketing should be maintained and argued that in view of the correlation between the existing methodology and the results of the time docketing study, the additional effort is not worthwhile.

10.2.5 CAC submitted that Centra should have undertaken a more comprehensive study of its customer accounting costs. CAC supported the existing methodology for the test year but submitted that Centra should be requested to investigate alternative methods of estimating the demands of each customer class on the customer accounting department.

10.2.6 IGUA agreed with the Company's position and submitted that the evidence suggests that the current weighting continues to allocate a reasonable amount of costs to each rate class.

10.2.7 OCAP submitted that Centra should adjust its weighting based on the time docketing study. In its view the Company in rejecting this study is applying its judgement to reject hard evidence that would benefit residential customers by between $266,100 and $368,200, or one to two dollars annually per household.

10.2.8 Centra submitted in reply that OCAP's position that the precise percentage allocation based on time studies should be used would apply to a future period only if the number of customers in each rate class changed at exactly the same rate. This is very unlikely to occur, and it argued that, since OCAP's recommendation likely ignores this fact, it should be rejected.

Board Findings

10.2.9 The Board finds that Centra’s time docketing study adequately validates a cost allocation based on the use of class weightings of Rate 01(1), Rates 10, 16 (5), Rates 20, 25, 100(10) combined with the number of customers in each rate class. The Board accordingly approves the current methodology and resulting cost allocation for the 1997 test year.

10.2.10 The Board notes that the Companies will need to review the allocation of customer accounting costs as a result of any introduction of ABC Service and the proposed merger of the Companies' customer accounting systems.

10.3 ALLOCATION OF BAD DEBT EXPENSE

10.3.1 Centra historically included its bad debt expenses as part of its customer accounting costs. In this proceeding Centra proposed a modified methodology for allocating forecast bad debt expense to rate classes.

10.3.2 In its E.B.R.O. 483/484 Decision the Board directed Centra to monitor the cause of, and recovery of, buy/sell customers' bad debt expenses and to report to the Board in Centra's next main rates case.

10.3.3 In E.B.R.O. 489, Centra stated that it had not had time to comply with the Board's direction. Centra proposed to continue to assign bad debt expenses in the same manner as the customer accounting expenses, while Board Staff proposed that the expenses be allocated in proportion to the revenue earned from each customer class.

10.3.4 In its E.B.R.O. 489 Decision the Board approved an interim allocation of bad debt expense for the 1995 test year. Centra indicated at that time that it had begun a study to determine the cause of, and level of recovery of, bad debt expense and the Board in its E.B.R.O. 489 Decision, stated that it expected Centra to file the results of the study in its next main rates case.

10.3.5 In this proceeding Centra filed the results of the study. It presented the results broken down between the general service classes and industrial classes. Each of these groups were further separated into buy/sell and system customer groupings. From 1991 through 1995 Centra incurred bad debt expenses of $1,158,000 in respect of Rate 01 system customers, $51,000 for Rate 10 system customers and $2,130,000 for industrial buy/sell customers. Of the $2,130,000 incurred due to industrial customers, $2,114,000 was attributable to Algoma Steel Corporation. Centra was at risk for this amount for several years until it was eventually repaid by Algoma, leaving $16,000 that was incurred on behalf of other industrial customers.

10.3.6 Centra proposed to base the test year allocation of bad debt expense on a forecast of the bad debt incurrence by each of the general service and industrial rate class groupings and then to use weighted customer allocation factors to allocate the costs within the general service and industrial classes.

10.3.7 The 1997 forecast of bad debt expenses included $292,308 related to large industrial customers and Centra proposed to allocate that expense to Rates 20, 100 and 25 customers in proportion to the weighted customer numbers in each class. The remaining bad debt expense of $332,692 was to be allocated to Rates 01, 10, and 16, again in proportion to the weighted customer numbers.

10.3.8 The impact of the proposed change in the test year would be to allocate $84,447 more to Rate 20 and $85,291 more to Rate 25, with all other rate classes receiving a correspondingly lower allocation.

Positions of the Parties

10.3.9 All parties to the ADR Settlement Agreement except IGUA agreed with the proposed change.

10.3.10 Centra submitted that the change was required to better reflect cost causality.

10.3.11 IGUA noted that following Centra's proposed change, Rates 20 and 25 will be assigned 28% of the total bad debt expense compared to the 7% approved by the Board in E.B.R.O. 489. IGUA submitted that the proportion of the bad debt expense proposed to be allocated to Rates 20 and 25 appears to be totally unreasonable when considered in the context of the revenues generated by Rates 20 and 25 in comparison to Rates 10,16 and 100. It argued that a persuasive case has not been made to justify an increase of between 340% and 400% to Rates 20 and 25. Accordingly IGUA argued that the bad debt expense should be reallocated in the same proportions as the Board found to be appropriate in its E.B.R.O. 489 Decision.

10.3.12 Board Staff submitted that Centra's proposal to differentiate between the general service and industrial classes for allocation of bad debt expense should be approved, since this will result in the allocation of the expense reflecting the manner in which it is incurred.

10.3.13 Centra in reply submitted that IGUA's position appears be based solely on the fact that the proposed change would assign more costs to Rates 20 and 25. The proposal is based on actual bad debt experience which indicates the need for segregation of rate classes. The methodology for forecasting bad debt expense has been refined to specifically account for the distinction between general service and large volume industrial service classes and it is reasonable that this distinction also be reflected in the cost allocation methodology.

Board Findings

10.3.14 The Board finds that Centra's method of forecasting bad debt expense by rate class takes into account historical experience, including the exposure of the Company to the Algoma bad debt. It is therefore appropriate that the cost allocation methodology be brought in line with the forecast.

10.3.15 Accordingly the Board approves the Company's change to the bad debt cost allocation methodology and the resulting 1997 test year allocations to the various rate classes.

CENTRA RATE DESIGN

10.3.16 Centra's evidence was that no changes to pricing structure, seasonal differentials or customer charges were proposed for 1997.

10.3.17 The following rate design issues were addressed in the proceeding:

- C Interruptible rates and policies - Rates 16, 25 and 30;
- C Load Balancing, Peak and Off-Peak Storage Services;
- C Fort Frances rates;
- C Alternative rates for power generating stations;
- ! Special Rate Class for Aboriginal Peoples; and
- C Revenue to cost ratios.

10.4 INTERRUPTIBLE RATES AND POLICIES - RATES 16, 25 AND 30

<u>Terms and Conditions of Service</u>

10.4.1 Centra has two interruptible rate classes, Rate 16, small volume, and Rate 25 large volume. Both rate schedules provide that customers are eligible for this service if they "in the judgement of the Company, can readily accept interruption and restoration of gas service."

10.4.2 Customers may elect, under either rate schedule, Sales Service or Transportation Service. The Rate 16 rate schedule sets out that the Sales Service is "For interruptible supply of natural gas by the Company and associated transportation services necessary for its delivery to the Customer." The Rate 16 Transportation Service is "For delivery of natural gas owned by the Customer on the Company's distribution system from the Point of Receipt on TCPL's system to the Point of Delivery on the Customer's or end-user's premises ...".

10.4.3 The Rate 25 rate schedule provides that the Sales Service is "For interruptible supply of natural gas by the Company and associated transportation services necessary to ensure its delivery in accordance with Customer's needs." The provision for Transportation Service on the Rate 25 rate schedule is similar to that for Rate 16.

10.4.4 Neither rate schedule makes reference to the circumstances under which service maybe interrupted although the Rate 25 rate schedule states that the service is available to ensure delivery in accordance with the customer's needs.

10.4.5 Customers taking service under Rate 16 or 25 must enter into the Service Agreement, *Agreement for Provision of One or More of Gas Sales, Transportation and Storage Services*. It provides in Article XXVI "Company or Customer may curtail or restore the delivery of gas to Customer under interruptible sales service upon giving Customer or Company, as the case may be, at least three (3) hours notice of the said curtailment or restoration of delivery ... If Customer fails to comply with a curtailment notice, Customer shall pay for any daily uncurtailed volume at the rate provided for in Article X..." Article X provides that volumes taken by interruptible customers in excess of those provided for constitute unauthorized overruns and shall be paid at 150% of the Upper SWIS Gas Supply Range. The Special Winter Interruptible Service ("SWIS") is found in the Rate 25 rate schedule. It is available from November 1 to April 15 and has a floor and ceiling ("upper range") on the gas supply charge. The actual rate paid is negotiable.

10.4.6 The current Rate 16 and Rate 25 rate schedules note that "Centra has a short-term intermittent gas service under Rate 30 ..." The Rate 30 rate schedule sets out that the service is available "For intermittent, short-term gas supply ... This may include situations where customer-owned gas supplies are inadequate and short-term backstopping service is requested or during a situation of curtailment on the basis of price when the purchased price of Spot gas is outside the Rate 25 SWIS price range ... The service is for intermittent gas supply only ..."

10.4.7 The Rate 30 rate schedule sets out that the gas supply charge shall be \$5.00 per 10^3m^3 "plus the greater of the incremental cost of gas for Centra and the customer's gas supply charge under the current Centra service rate."

10.4.8 The reference to the Rate 25 SWIS price range in the Rate 30 rate schedule was approved by the Board in the E.B.R.O. 489 Decision. In its pre-filed evidence in E.B.R.O. 489 Centra stated that it "does not anticipate that there would be numerous transactions of this type due to the unusual circumstances that would have to prevail. The customer would have to be in a situation where it cannot, or will not, use its alternative fuel or otherwise accept interruption. Gas must be available only at a price higher than can be accommodated under the Rate 25 upper SWIS limits and, finally appropriate transportation between the source of the gas and Centra's franchise area, must also be available. Nevertheless, it is appropriate to have a mechanism available to provide service should all of those conditions prevail."

Operation of Interruptible Service in 1996

10.4.9 During the summer of 1996 and prior to the commencement of the hearing the Board received several letters from interruptible customers complaining that Centra had given them notice of curtailment. The notices from Centra which accompanied these letters indicated that increased gas costs led to the need for curtailment. The customers were all offered Rate 30. Some of the notices referred to the fact that increased gas costs might continue for the summer and therefore the need for curtailment. In some of the notices, Centra offered customers "summer supply at a rate of $133.00 ...". Other notices referred to a price of "up to $133.00 ..." Customers were asked to notify Centra whether they accepted "this interim price".

10.4.10 The Board Secretary replied to these letters stating that it did not appear that Centra had acted in violation of the rate schedules approved by the Board and noted that Interruptible Service was on the E.B.R.O. 493 Issues List.

10.4.11 During the course of the E.B.R.O. 493/494 hearing the Board received a letter of concern from the Ontario Hot Mix Producers Association ("OHMPA"). The letter indicated that its members account for 94% of Ontario's asphalt production which is seasonal in nature with all production occurring between May and December. It further indicated that many of OHMPA's members were on Centra's Rates 16 and 25 and that historically interruptions were infrequent and short in duration. The letter also indicated that virtually no notice was provided for the interruptions in the summer of 1996 and therefore there was no reasonable basis to provide for the curtailment. OHMPA stated that as far as it was aware Centra had not given notice at the time of renewal of its members' contracts the fact that there may be interruptions due to limited firm capacity on TCPL. OHMPA suggested that rates paid by seasonal customers and the operation of buy/sell and bundled-T arrangements for these customers should be reviewed by Union and Centra.

10.4.12 Centra did not pre-file any evidence with respect to its interruptible rates other than a revised Rate 30 rate schedule which provided for a negotiable short-term rate for storage and load balancing.

Centra's Evidence on Reasons for Curtailment

10.4.13 During the hearing Centra's witnesses testified that Centra had had to curtail interruptible customers during the 1996 in order to serve firm customers. Their evidence was that in recent years Centra's load factor on TCPL has increased from 88% to 100% except in the Manitoba and Western Delivery Areas. They stated that Centra does not contract for firm TCPL capacity to serve interruptible customers and that in the summer of 1996 the firm TCPL capacity was required to serve firm customers including moving gas to storage for those customers. In addition, TCPL capacity was trading on the secondary market at a premium. As a result, Centra's witnesses testified the cost of serving interruptible customers was in excess of the cost being recovered in Rates 16 and 25. For these reasons Centra gave some of the Rate 16 and 25 customers notices of curtailment.

10.4.14 It was also Centra's evidence in this and other proceedings, notably the E.B.L.O. 251, Bright to Owen Sound proceeding, that Centra had been reviewing its arrangements for moving gas to storage in the summer to meet its firm customers' requirements. Centra's staff had determined that Centra was relying on interruptions, diversions and exchanges to move this gas. These arrangements, they had determined, were not appropriate for meeting firm demand. Therefore, Centra moved to ensure that firm transportation was available to move supplies for firm customers to storage in the summer months.

10.4.15 In addition, in this proceeding it was Centra's evidence that Centra was unable to "down-stream divert" because TCPL did not have sufficient down-stream capacity and that interruptible capacity on TCPL was only available at a substantial premium to firm service.

10.4.16 Centra's evidence was that Rate 16 and 25 customers who are curtailed have several choices. They could avail themselves of Rate 30, they could arrange their own supplies and bring them in on a Rate 16 or 25 T service or they could use their alternative fuel source. In addition, Rate 25 customers can renegotiate their Rate 25 rate to the upper limits of Rate 25.

10.4.17 The evidence showed that several Rate 25 customers renegotiated their Rate 25 rates while some of them did not receive curtailment notices since these customers were paying "a price that would recover the costs that [Centra] would incur to serve that customer."

10.4.18 Centra's witnesses further testified that its sales representatives communicate the projected level of curtailments for the year based on normal weather and plans. Those Rate 25 customers who negotiate a rate in the upper end of the Rate 25 range may be curtailed less than other interruptible customers.

10.4.19 It was acknowledged by Centra's witnesses that firm customers benefit from interruptible customers in that the right to interrupt results in the smaller system design. The witnesses observed that if the Utility interrupts too frequently the Utility may lose the benefit of having interruptible customers on the system since those customers will wish to become firm customers necessitating the Utility to incur added costs to obtain facilities to serve them on a firm basis.

10.4.20 Centra's witnesses also pointed out that interruptible customers benefit from interruptible rates since they are able to choose which fuel to use on the basis of price. This right, the witnesses noticed was exercisable at any time by Centra's interruptible customers without notice or penalty.

<u>Rate 30</u>

10.4.21 The volumes that buy/sell interruptible customers consumed under Rate 30 were not credited to their buy/sell balances. Centra's witnesses explained that the buy/sell volumes were being purchased under one contract and the volumes were being sold to the interruptible customers under Rate 30 which is a separate and unrelated contract.

10.4.22 Centra's witnesses testified that Rate 30 is not offered for a term and that customers are not forced to take Rate 30 for a long period of time. However, it was Centra's evidence that all Rate 16 customers except those in the Manitoba and Western Delivery Areas were given curtailment notices and that approximately 90% of those customers went on to Rate 30 and Centra forecast that they would remain on Rate 30 to the end of 1996.

10.4.23 For Rate 25 the maximum negotiable rate for sales service for the summer of 1996 ranged from $\$135.90/10^3m^3$ to $155.48 depending on the delivery zone. For Rate 16 the rate was ranged from $0.5260 to $0.5577 per m^3 depending on the delivery zone.

Positions of the Parties

10.4.24 While not pursuing the point ECNG did comment in argument that it believed that "there are strong civil suit possibilities ...". The remainder of the parties presenting arguments on the issue of Centra's treatment of its customers under Rates 16 and 25 took the position that Centra was acting within the terms of its approved rate schedules and underlying contracts.

10.4.25 Comsatec argued that Centra's assertion that TCPL firm capacity was not available in the summer of 1996 to serve interruptible customers was overstated. It was Comsatec's submission that the evidence showed that after firm service and deliveries to storage, there was from 326,000 to 453,000 $10^3m^3/d$ of firm TCPL capacity available to serve interruptible customers.

10.4.26 Comsatec further argued that Rate 16 customers were generally smaller industrial customers with marginal operations providing employment to many people. Historically these customers have expected reasonable delivery of their annual volumes under Rate 16 charges. Comsatec also submitted that since the average Rate 16 delivered price was about $150 per 10^3m^3, these customers were not a burden on Centra's system and should not have been curtailed.

10.4.27 ECNG argued that both Utilities had allowed their proportion of firm TCPL capacity to decline beyond a reasonable level and that in this "transition period" the Utilities should remain the primary source of balancing and coordination of the system and direct purchase supply streams.

10.4.28 ECNG observed that Centra's interruptions in the summer were not as a result of peak day conditions and argued that Centra's "deliverability" problem should never have been allowed to develop to the degree that it did and that, having developed, Centra should have dealt with it more in the public interest and in a "far less discriminatory" manner than it did.

10.4.29 ECNG did not dispute Centra's assertion that it was required to acquire additional TCPL capacity at a premium in the secondary market in order to meet its customers' requirements for the summer of 1996 but questioned whether the full burden of paying this extra cost should fall on interruptible customers when they were simply requiring "their predictable, projected summer deliveries" ECNG submitted that interruptible customers' summer deliveries had filled Centra's "summer valleys" and contributed towards Centra's ability to meet winter peak demands.

10.4.30 It was noted by ECNG that in the past few years Centra had been purchasing spot supplies for its system customers. All customers benefitted, it argued, including system customers since spot prices were lower than firm prices. This policy ECNG argued, was reasonable but now that circumstances have changed, the situation must be dealt with equitably.

10.4.31 It was ECNG's position that deliveries to interruptible customers should have been made at the original contracted prices and any variations in price should have been recorded in the spot gas deferral account for disposition to all bundled customers.

10.4.32 With respect to Centra's argument that it was within its contractual rights in curtailing the Rate 16 and 25 customers, ECNG argued that the Board should not approach the question of establishing equity among customers on the basis of "narrow legalities", rather the Board should determine what is fair and reasonable on the basis of the broader public interest.

10.4.33 It was ECNG's position that the Board should rescind Centra's "interruptible" price increases, add those amounts to the spot gas deferral account and distribute the balance of that account to all bundled customers.

10.4.34 With regard to Centra's proposed increases in Rate 16 and 25 for 1997, ECNG argued that these increases were not in the public interest since their calculations showed that for Rate 16 the increase would result in rates in excess of those that would be incurred under Rate 10, a firm service, and for Rate 25 the increases would result in rates approaching those that would be incurred under the alternative firm industrial rate.

10.4.35 In argument, IGUA pointed to the testimony of its witness, the Manager of Technical and Energy Services for Falconbridge Limited, that as late as the spring of 1996 Centra's sales representative was making representations as to the reliability of Centra's interruptible service. IGUA argued that despite these representations, there was no non-system gas interruptible delivery service available from Centra. It submitted that what Centra was providing was a spot gas displacement service for which customers were required to pay the prevailing market spot gas prices in exchange for their delivery to Centra of customer owned non-system gas at the prevailing buy/sell reference price.

10.4.36 IGUA took exception to Centra's contention that customers were only required to pay the prevailing market spot gas prices on an intermittent basis, noting that a Rate 25 customer that renegotiated under Rate 25 remains on the renegotiated rate unless the customer curtails in order to trigger "fresh price negotiations". With respect to those customers that switched to Rate 30, IGUA observed that they remained on Rate 30 until the customer took some initiative, thereby also belying Centra's contention that the use of Rate 30 was intended to be intermittent. IGUA also referred to the language of the curtailment letters and sample agreement to support its contention that Centra was not using the prevailing spot gas market price on an intermittent basis.

10.4.37 It was alleged by IGUA that since Centra did not take any steps to alter its arrangements with interruptible customers when Centra's cost of spot gas fell below the price being paid by interruptible customers under the altered contracts, either Rate 25 or 30, Centra may have profited significantly.

10.4.38 IGUA submitted that the Board should issue the following directions:

(a) require Centra to produce a rate schedule which describes in clear and unambiguous terms the spot gas interruptible service which it can provide to system and non-system gas interruptible customers, ...;

(b) require Centra to refrain from misrepresenting the quality of the interruptible service which it is able to provide;

(c) in situations where service can be provided under Rates 16 and 25 pursuant to existing contracts between Centra and its interruptible customers, require Centra to provide such service and to immediately restore service under such rates in a situation where service under the spot gas interruptible service rate schedule is no longer necessary because of a decline in spot gas costs being incurred by Centra; and

(d) require Centra to account to its Rate 16 and Rate 25 customers for any amounts which it has collected through its administration of Rates 16 and 25 and Rate 30 in excess of the actual costs incurred by Centra to obtain spot gas to provide service to those customers.

10.4.39 Board Staff also argued that the evidence showed that Centra had not provided its interruptible customers with reliable information on the risks and benefits of taking interruptible service and that the Utility has an obligation to sell its services in a responsible fashion. Board Staff noted Centra's evidence on its success in improving its load factor and the fact that the implications of this had not been communicated to interruptible customers.

10.4.40 Board Staff's concerns about Centra's treatment of its interruptible customers were heightened by the fact that Centra has a vested interest in the transactions since the evidence showed that Rates 25 and 30 "provide the opportunity for windfall profits to the shareholder." As it was, any difference was used to offset PGVA debits allocated to the interruptible classes. Board Staff observed that there was no evidence on the total margin on Rate 25 and 30 revenues for 1995 and pointed to the concern expressed by the Board in its E.B.R.O. 489 Decision where the Board stated:

Moreover, the sale of spot gas at a higher than purchase price means that, in addition to the margin to be earned through the delivery charge, Centra will

> *also be making a margin on the gas supply component. This appears to be contrary to the notion that Centra is not "profiting" from the sale of gas as a commodity. Centra is expected to also address this matter at its next main rates case.*

Board Staff observed that Centra had not addressed the Board's concern in this proceeding.

10.4.41 In Board Staff's view the contracts and rate schedules provide for curtailment due to price as well as any other reasons and Centra is only bound by these contracts and rate schedules subject to an implied term of good faith.

10.4.42 Board Staff submitted that it is reasonable to interrupt on the basis of price and that it is prudent to withdraw firm transportation from interruptible customers to serve firm customers. Board Staff noted that in the past when Centra's load factor was lower, there was less chance of interruptions but now that the load factor is higher there is an increased chance of interruptions.

10.4.43 Board Staff submitted that given this change there would be merit in a review of Centra's interruptible services noting that the Rate 25 range rates and Rate 30 provide for "firmer" interruptible services at a price. Board Staff also noted that clarifying the terms under which interruptible rates are offered would alleviate some parties' concerns.

10.4.44 With respect to Rate 30, Board Staff argued that while it supported the continued use of the rate it was clear that Centra was using it for a purpose other than its intended purpose of an intermittent backstopping service.

10.4.45 In addition, Board Staff observed that while it was Centra's position that the $5.00 surcharge was intended to discourage the prolonged use of Rate 30, many customers had been and would be on Rate 30 for a prolonged period of time. Board Staff concluded that Centra had been able to make use of unutilized transportation capacity on a day-to-day basis or its market dominance to achieve lower prices.

10.4.46 Board Staff observed that if natural gas is priced competitively in Alberta then there is no reason why a buyer would pay a $5.00 surcharge. However, when it is recognized that the relevant price for gas is the landed price, if Centra is able to use any of its transportation capacity to land gas it will beat the market. In Board Staff's view the $5.00 surcharge simply provides a means under certain circumstances for Centra to recover the value of unutilized transportation assets and transfer this value to the shareholder since these revenues are not forecast.

10.4.47 Board Staff submitted that IGUA's specific recommendations would be a good starting point for a review of Centra's (and Union's) interruptible policies.

10.4.48 In reply, Centra, in rejecting most parties arguments, relied in large part on the fact that it was acting within the terms and conditions of its interruptible rate schedules and contracts with its interruptible customers.

10.4.49 Centra stated that there was no merit to the argument that it had expropriated buy/sell interruptible customers' gas in that that gas was delivered to Centra in Alberta and Centra paid a price for that gas which reflected its value delivered in Alberta. Without firm transportation from Alberta to Ontario that gas has no value beyond the reference price paid for deliveries at the Alberta border.

10.4.50 It was submitted, on behalf of Centra that, there was only one piece of evidence to support the allegation that Centra had misrepresented the nature of its interruptible services and that it was unfair and wrong to use this evidence to infer that Centra generally misrepresents the nature of its interruptible services.

10.4.51 In response to argument by Kitchener and ECNG, Centra took the position that past practices do not restrict the Utility's ability to rely on the terms and conditions of its contracts and rate schedules when determining whether or not to interrupt its customers.

10.4.52 With respect to ECNG's argument that Centra should acquire more firm TCPL capacity in order to provide valley capacity for its interruptible customers, Centra argued that it was unclear who would pay for or accept responsibility for the UDCs if the capacity is not used. Nor did the proposal take into consideration the fact that Centra's interruptible customers can interrupt at any time.

10.4.53 With respect to IGUA's recommendations, Centra submitted that there was no basis for any of the recommended actions.

10.4.54 With respect to ECNG's proposal that costs recovered through Rates 25 and 30 be added back to a deferral account and returned to all bundled customers, Centra argued that there was no basis to support this proposal since Centra was clearly acting within its rights in taking the action that it did.

Board Findings

Changed Conditions

10.4.55 The Board observes that, apart from ECNG, no party disputed that, throughout 1996, Centra was acting within the terms and conditions of its Rate 16 and 25 rate schedules and underlying contracts. It appears to the Board that these terms and conditions have not been an issue in the past; however, changing conditions and policies have called into question the nature of Centra's interruptible services, the terms and conditions of its interruptible rate schedules and the underlying contracts.

10.4.56 The changed conditions and policies included:

- the improvement in Centra’s load factor as evidenced in the E.B.R.O. 489 proceeding;
- Centra’s recent change in policy regarding the use of firm capacity to transport gas to storage in the summer for its firm customers (as opposed to diversions, interruptions and exchanges); and
- the trading of TCPL capacity at a premium during 1996 resulting in delivered gas supply prices in excess of firm gas prices largely because of limited TCPL capacity.

All of these factors appear to have led to the change in the quality of Centra's interruptible services in the summer of 1996.

10.4.57 The Board agrees with parties who argued that Centra's ability in the past to use summer valley capacity on TCPL to serve interruptible customers and to purchase lower price spot gas for firm customers has benefitted all of Centra's customers. Given the fact that Centra had undertaken a review of its use of its firm transportation on TCPL, which would impact on the level of service available to interruptible customers, the Board would have expected Centra to alert its interruptible customers to the change, given them more time to make the necessary adjustments to their energy plans, and worked with these customers to assist them in making the necessary adjustments.

10.4.58 It is clear to the Board that in the summer of 1996, Centra was interrupting or curtailing customers on the basis of price, that is, the cost to serve these customers was in excess of the rates being charged under the relevant rate schedules and therefore the customers were curtailed for this reason. It also appears to the Board that there was little understanding on the part of Centra's interruptible customers, especially the summer interruptible customers, that they could or would be curtailed for price reasons and for long periods of time. Centra based its interruptions and redefined the quality of its interruptible services on the customer's willingness to agree to a higher price. Rate 25 customers could negotiate a new price under Rate 25 if the cost to serve them fell within the Rate 25 range rates. Alternatively Rate 25 customers could use Rate 30. For Rate 16 customers, if they wanted to continue to receive gas service the only alternative was Rate 30 under which they were required to pay a \$5.00 per 10^3m^3 surcharge.

10.4.59 The Board recognizes that interruptible customers, by definition, have or should have an alternative source of energy and that, given the fact that many interruptible customers either agreed to be served under Rate 30 or renegotiated their Rate 25 contracts for extended periods, the Board must assume that their alternative sources of energy were priced higher than the gas service Centra was offering under either service.

Rate 30

10.4.60 The Board has a great deal of concern for the manner in which Rate 30 has been applied. The Board has considered the option of limiting the duration of Rate 30, however, as such limitations may impair the ability of this rate offering to fulfil the backstopping requirements it was intended to provide, the Board determines that restrictions on the duration of the service are not appropriate at this time.

10.4.61 The $\$5/10^3m^3$ charge assessed on Rate 30 volumes is not cost based and was, according to Centra, intended to discourage prolonged use of this rate. Nonetheless, the rate was clearly used for prolonged periods during 1996. The Board notes that Centra has certain advantages in its ability to provide the gas supply needs of Rate 30 customers. Centra can quickly consolidate the needs of multiple customers, its regular purchasing activities enable Centra to act on a timely basis, Centra is in a position to be able to terminate the Rate 30 service offering once gas costs have declined to a level where a customer can resume service under the original interruptible service contract, and ABMs may be looking for a higher fee or require a term of service that a customer would not be prepared to commit to under an “intermittent” service revokable on three hours notice. With the competitive limitations on this service, the Board finds that the $\$5/10^3m^3$ charge is unduly punitive. The Board directs Centra to assess the relevant costs associated with providing Rate 30 service, and report to the Board in its next main rates case. In the interim, any revenues resulting from this service shall be separately recorded in Centra’s spot gas deferral account.

10.4.62 The Board agrees with IGUA that, since Centra did not take any steps to alter its arrangements with interruptible customers when the cost of gas fell in the summer period, Centra may have profited. The Board also agrees with Board Staff that enabling a utility to earn a margin on the gas supply commodity are “destructive to the building of a competitive natural gas market.” The Board finds that the extra margin collected on the gas supply component from customers who renegotiated under Rate 25 and from Rate 30 customers during fiscal 1997, in excess of the cost to Centra, shall be separately recorded in Centra’s Spot Gas Deferral Account.

10.4.63 In addition, the Board agrees with parties that Centra did not put in place a system that in fact would make Rate 30 an "intermittent" rate, whereby a customer would be returned to its original rate (for Rate 16 customers) or original contract (for Rate 25 customers who have not renegotiated their rate) if the price of spot gas returned to the original Rate 16 or 25 range rate level. The Board directs Centra to immediately restore service pursuant to the existing Rate 16 and 25 contracts in a situation where service under the Rate 30 is no longer necessary because of a decline in the spot gas costs being incurred by Centra to serve these customers.

10.4.64 Further, the Board directs Centra to develop standard information on the quality of its interruptible service for its sales representatives to provide to its interruptible customers and to file a copy of this information in its next rates case.

Future Rate Design

10.4.65 The Board was provided with no evidence upon which to base an assessment of the value of interruptible customers to the system as a whole in relation to the current rate design. The Board is of the view that it would be timely for Centra to review, in consultation with representatives of the interruptible customers, the make-up, and service limitations, of its interruptible classes, and the value of interruptible service to the system. The Board directs Centra to include the results of this review in its proposed rate design for the next main rates case.

10.4.66 During the proceeding it also became apparent that the customers served under Centra's interruptible rate class have differing consumption characteristics, and many customers are requesting greater predictability in the quality of interruptible service. The Board observes that the manner in which Centra applied its Rates 16, 25 and 30 to summer interruptible customers does not appear to take into account the benefit these customers provide as an alternative to summer capacity to meet storage injection requirements and by avoiding potential unabsorbed demand charges during periods of excess storage inventory levels during the summer valley period. The Board directs Centra to examine the potential for a summer rate as advocated by the OHMPA and other seasonal users and to file this study in its next rates case.

10.4.67 Further, the Board directs Centra to file in its next main rates case its queuing policy for firm service, and in particular, the details of the policy with respect to interruptible customers who wish to become firm service customers.

Treatment of Interruptible Customers' Buy/Sell Volumes

10.4.68 The Board observes that interruptible customers enter into separate contracts with Centra. One contract is for the sale of gas to Centra under buy/sell arrangements and the other is for the purchase of interruptible gas from Centra. Elsewhere in this Decision the Board has noted that buy/sell volumes are considered to be firm supplies. For these reasons the Board does accept parties' arguments that volumes consumed under Rate 30 should not be credited to buy/sell contracts.

10.5 FORT FRANCES RATES

10.5.1 Rates for customers in Centra’s Fort Frances delivery area were scheduled to be combined with overall system rates effective January 1 1997. However, based on the Company’s original forecast revenue deficiency, this would have resulted in an overall rate increase higher than 10% above the rate increase for other Centra delivery zones. Accordingly Centra proposed to cap the rate increase at 10% higher than the delivery rate increases for other zones and where possible to make the rates in the various delivery blocks equal to the rate charged in other zones.

10.5.2 The Company subsequently submitted an updated filing which forecast an increase in the 1997 revenue deficiency which would result in significant increases to average residential rates. Accordingly the Company as part of the mitigation measures requested by the Board, proposed to defer the next step in levelizing the Fort Frances delivery zone rates until January 1, 1998. No parties disagreed.

10.6 ALTERNATIVE RATES FOR POWER GENERATING STATIONS

10.6.1 This issue was added to the issues list at the request of TCPL. The underlying proposition was that Rate 100 does not provide an appropriate rate design for power generation facilities and that as a result Rate 100 over collects from that group of customers.

Positions of the Parties

10.6.2 Board Staff noted that it had argued against end use customized rates in other proceedings because in its view, such rates are inherently unfair to other customers with similar load characteristics. Staff also noted that the Board has ruled against such proposals in the past; for example, Centra's proposal for a special cogeneration rate was denied by the Board in E.B.R.O. 467.

10.6.3 Board Staff submitted that there was no evidence to suggest an alternative rate class and that Rate 100 provides an appropriate rate for high volume/load factor customers such as power generating stations. Staff further submitted that Rate 100's proposed cost recovery for the test year is just and reasonable.

10.6.4 TCPL submitted that the evidence shows that TCPL, as the shipper for its Kapuskasing and North Bay electrical generating plants, is disadvantaged by the rate design used in Rate 100. Both projects have positive cash flows by the second year of their operation and the overall profitability indices are 4.52 for Kapuskasing and 4.33 for North Bay. In TCPL's view this is because the facilities involved are minimal and the plants are in a rate class which includes a premium for risk even though they add no risk themselves.

10.6.5 TCPL stated that it is not proposing that an alternative rate class be established in 1997, although in the long run this will be necessary. However TCPL argued that Rate 100 customers are overcharged as indicated by the forecast class revenue to cost ratio of 1.0581 and the excess revenue prediction of over $7 million in 1997 and that Centra should be directed to adjust the revenue to cost ratio to unity. TCPL submitted that a recalculation of rates based on a revenue to cost ratio of one would be consistent with the Board's direction to bring rates closer to target rates of return as set out in its Decision in E.B.R.O. 489.

10.6.6 TCPL also submitted that the Board should require Centra to take further steps in the creation of rate classes for the purpose of ensuring a fair allocation of costs based on cost causation. In TCPL's view the current design of Rate 100 does not do this at present and the Board should direct Centra to address in the next application the ratemaking concerns of parties whose facilities are nominal in comparison to the cost of service they are required to pay.

10.6.7 Centra in reply, while noting the position of TCPL, agreed with Board Staff's submission that Rate 100 already provides an appropriate rate for large volume high load factor customers.

10.7 PROPOSED SPECIAL RATE CLASS FOR ABORIGINAL PEOPLES

10.7.1 The Ontario Native Alliance set out in its written evidence some historical background on the aboriginal peoples in North America, and outlined some of the positions that ONA has taken on behalf of its members in past Board proceedings. In its argument, ONA submitted that "The economic and industrial development (of North America) has been conducted at large costs to the individual and collective rights and well being of aboriginal people", and suggested that the cost allocation and rate design process for the Utilities might provide an avenue of redress.

10.7.2 The specific relief sought by ONA included:

- an order from the Board that Centra or its successor institute and fund an assessment to identify and quantify the likely and potential costs in respect of its responsibility for redress of aboriginal grievances to be conducted in consultation with aboriginal stakeholders; and

- an order from the Board that Centra, or its successor, evaluate the establishment of a rate class for the purpose of providing redress to aboriginal peoples for historical grievances, and report thereon at the next rate hearing.

10.7.3 ONA argued that the special rate class is justified as a means of paying deferred costs for redress over time.

10.8 REVENUE TO COST RATIOS

10.8.1 Centra's evidence was that it continues to base its cost allocation using the average rate of return for all classes, while taking into account the potential impact of any proposed change on customers and the customers' expectations of rate stability and predictability.

10.8.2 Centra indicated that its test year forecast revenue to cost ratios are generally consistent with the target rates of return approved by the Board in its E.B.R.O. 489 Decision.

Positions of the Parties

10.8.3 TCPL had specific submissions on the revenue to cost ratios for Rate 100 which are addressed under the heading "Alternative Rates for Power Generation Facilities".

10.8.4 Board Staff submitted that the revenue to cost ratios proposed by Centra for the test year should be accepted since the target rates of return were consistent with those set by the Board in E.B.R.O. 489.

10.9 LOAD BALANCING, PEAK AND OFF-PEAK STORAGE SERVICES

10.9.1 Centra proposed to make load balancing services available as a supplement to existing bundled delivery and transportation services, initially for industrial customers under Rates 20, 25 and 100. The services would include gas loans at negotiated prices, off-peak storage and peak storage. These services are currently available from Union's S&T department. Including them on Centra's rate schedules will streamline the transaction with the customer and provide equal access to load balancing services for all customers of the two Companies regardless of geographic location.

Positions of the Parties

10.9.2 The positions of the parties on this matter are set out in the comparable section of Chapter 9.

Board Findings

Load Balancing, Peak and Off-Peak Storage Services

10.9.3 The Board finds it appropriate that Centra should offer load balancing, off-peak storage and peak storage services to industrial customers on terms similar to those pertaining to Union's industrial customers. In this connection, the Board's findings respecting these services applicable to Union and made elsewhere in this Decision shall apply equally to Centra in the test year.

Fort Frances Rates

10.9.4 The Board finds it appropriate to defer implementation of the next step in harmonizing the Fort Frances rates with other zones given the significant general increase in delivery charges embodied in the 1997 rate proposals. In the event that the proposed amalgamation of the Companies is approved by the LGIC, the Board expects that the issue of harmonization of Fort Frances rates will be revisited.

Alternative Rate for Power Generating Stations

10.9.5 The Board finds no new evidence which warrants a reconsideration of the rate design for Rate 100. Accordingly all large volume/high load factor customers, including power generation stations, will continue to receive service under the current Rate 100 in the test year.

Proposed Special Rate Class for Aboriginal Peoples

10.9.6 The Board is required by its legislation to "fix just and reasonable rates", and in doing so it attempts to ensure that no undue discrimination occurs between rate classes, and that the principles of cost causality are followed in allocating costs underlying the rates. While the Board recognizes ONA's concerns, the Board finds that the establishment of a special rate class to provide redress for aboriginal consumers of Centra does not meet the above criteria and is not prepared to order the studies requested by ONA.

Revenue to Cost Ratios

10.9.7 The Board finds that Centra's revenue to cost ratios as filed in its updated evidence at the end of the oral hearing are appropriate as a base for the determination of 1997 test year rates.

10.9.8 The Board directs Centra to make the adjustments to cost allocation resulting from its Findings regarding the 1997 cost of service and specific cost allocation issues. To the extent that the Company's proposed cost allocation changes were not reflected in the Company's proposed 1997 rates, and these changes were approved by the Board, the Board understands that the Company will not reflect these cost allocation changes in 1997 rates.

11. DIRECT PURCHASE ISSUES

11.0.1 The direct purchase market in Ontario continues to evolve as does the development of a competitive gas commodity market. The Utilities proposed a number of changes, as set out in paragraph 11.1.19, that affect the terms and conditions of direct purchase in their franchise areas. In the Board's view these changes represent a fundamental change in the direct purchase arrangements. The following brief review of the development and current status of direct purchase in Ontario provide a context for these proposed changes.

11.1 A BRIEF HISTORY OF DIRECT PURCHASE IN ONTARIO

11.1.1 Prior to 1985 the LDCs in Ontario obtained the bulk of their gas supplies through long-term contracts with TCPL. These contracts provided for both the supply and transportation of the commodity from western Canada to the LDCs' franchise areas in Ontario. End users were unable to arrange for their own supplies of gas.

11.1.2 The development of direct purchase began with the signing of The Agreement on Natural Gas Markets and Prices by the Governments of Canada, Alberta, British Columbia and Saskatchewan on October 31, 1985 ("the Halloween Agreement"). The Halloween Agreement provided that "... consumers may purchase natural gas from producers at negotiated prices, either directly or under buy-sell arrangements with distributors...".

11.1.3 At the time of the Halloween Agreement, TCPL was the prime long-term supplier, transporter and marketer of natural gas in eastern Canada and the LDCs in Ontario were under long-term contractual obligations to TCPL for the supply of the commodity and the transportation of the commodity from western Canada to Ontario. These contractual obligations represented most of the gas supplies that could be moved from western Canada to eastern Canada. Therefore, customers wishing to purchase gas directly could only do so by displacing the LDCs' contracted volumes.

11.1.4 When customers began to displace the LDCs' volumes by purchasing their supplies directly instead of through the LDCs, the LDCs were still liable to pay a financial penalty in the form of unabsorbed demand charges ("UDCs") for any shortfalls in their contracted volumes. In addition, direct purchasers holding capacity on TCPL were also liable for UDCs for any shortfalls in their contracted volumes. Various decisions by the NEB and this Board coupled with changes in contracting practices alleviated these problems and enabled direct purchasers to displace the LDCs' volumes relating to both the gas commodity and its transportation.

11.1.5 An additional barrier to the development of a direct purchase market in Ontario was, and continues to be, the existing legislation which regulates the supply of the natural gas commodity to consumers in Ontario. Early in the development of the direct purchase market in Ontario the Board determined that ABMs were suppliers of gas within the meaning of the relevant legislation.

11.1.6 To avoid the necessity to come before the Board under the Act, parties wishing to facilitate direct purchase, transfer title to gas to be delivered to consumers in Ontario to an Ontario LDC outside of the province, and the gas is then delivered to the consumer in Ontario via the LDC's pipelines under Board-approved tariffs. Title to gas is transferred from the LDC to the end-use customer at the customer's burner tip.

11.1.7 The two forms of direct purchase envisioned by the Halloween Agreement have developed and now comprise the bulk of gas consumed in Ontario. The first involves customers purchasing and taking title to gas outside of the province and arranging for transportation of that gas via TCPL and the LDC to the burner tip ("T-service"). Title to the gas commodity is never transferred to the LDC.

11.1.8 There are two types of T-service; unbundled T-service, that is, customers simply pay for transportation; and bundled T-service, that is, customers pay a bundled rate for all of the LDC's services except for the provision of the commodity. T-service customers are generally large volume customers with consistent load factors.

11.1.9 The second form of direct purchase envisioned in the Halloween Agreement was buy/sell. This form of direct purchase involves customers or their agents, brokers or marketers ("ABMs") purchasing gas and selling it ("buy/sell volumes") to the LDCs either in western Canada or at the Ontario border. The price paid by the LDCs for the buy/sell volumes is known as the buy/sell reference price ("buy/sell reference price"). Those volumes sold to the LDCs in Western Canada are transported to Ontario via the LDCs' contracted capacity on TCPL where they become part of the LDCs' system supplies. Generally buy/sell customers remain sales customers of the LDCs, that is they pay a rate, known as a sales rate, for the provision of full gas services by the LDC. Included in that sales rate is the LDC's forecast cost of the natural gas commodity. Customers who continue to purchase gas from the LDC also pay a sales rate and are referred to as system customers and their gas supplies are referred to as system supplies.

11.1.10 Buy/sell arrangements enable ABMs to aggregate a number of small volume customers making access to direct purchase feasible for those customers. In addition, particularly in the residential market, these arrangements do not require Board orders in order to supply gas to consumers in Ontario, in that ABMs do not bill customers for gas sold to them in Ontario; rather, the buy/sell customer generally receives a portion of the difference between the price that the ABM pays for gas and the price paid to the ABM by the utility which is the Board approved buy/sell reference price. Also, in this way, buy/sell arrangements do not necessitate a separate billing system.

11.1.11 With the development of buy/sell in the late 1980's the Board had to consider the nature of buy/sell supplies and the price to be paid for such supplies. In a series of parallel Decisions dated April, 1989 (E.B.R.O. 440-2, 452-3 and 456) relating to all three major Ontario LDCs, the Board noted that:

- *buy/sell customers who repurchase gas under firm sales rates require the LDC to supply gas to them on a firm basis. Therefore, ... it is reasonable to require such customers to supply the gas to the LDC on a similar firm basis; and*

- *in the case where a buy-sell customer purchases its gas from the LDC under an interruptible sales service contract, the Board is of the opinion that the LDC should still be able to receive a firm supply of gas, with an obligation to deliver, from the buy/sell customer. The LDC's offer of an interruptible sales service rate is premised on its ability to redirect the interrupted volumes for firm use elsewhere, and to also utilize freed-up capacity to the benefit of the system.*

11.1.12 Therefore, the Board accepted that all gas volumes delivered to the LDCs under buy/sell arrangements should be delivered on a firm basis. The evidence on the Minimum Conditions of Supply in the Direct Purchase hearing also confirmed that buy/sell supplies are firm supplies underpinned by contracts of one year or greater.

11.1.13 Having decided that all buy/sell volumes were to be considered firm volumes, the Board concluded that the buy/sell reference price should be the LDCs' firm WACOG.

11.1.14 In the early 1990s, Union began using the weighted average cost of all of its gas supplies, including spot gas, to calculate its buy/sell reference price. In the Board's E.B.R.O. 476, 485,474-B/483/484 Decision on Direct Purchase dated April 27, 1994 ("the Direct Purchase Decision"), the Board noted differences in calculating the buy/sell reference prices and set out certain directions and expectations with respect to achieving greater consistency among the practices of the LDCs. The LDCs have not as yet reconciled the differences.

11.1.15 Centra's firm WACOG and therefore its buy/sell reference price reflects Centra's cost of gas in western Canada, not the cost of gas delivered to Ontario. Union has several buy/sell reference prices based on: whether the supplies are delivered at the Ontario border or in western Canada; whether they are delivered by firm service ("FS") or FST; and whether they are obligated or unobligated deliveries.

11.1.16 While the direct purchase market has continued to grow, TCPL remains the major source of transportation to Ontario. At the same time, the proportions of the LDCs' firm system supplies from western Canada have been reduced by customers moving to direct purchase and hence the TCPL capacity that remains to be displaced under the LDCs' contracts has also decreased.

11.1.17 In its E.B.R.O. 489 Decision with Reasons - Part II, the Board noted that 80% of Centra's gas supply requirements are obtained through direct purchase arrangements. The Board also recognized the inherent difficulties in attempting to regulate a competitive market on the basis of regulatory principles applicable to a monopoly. The Board instructed Board Staff to work with stakeholders and to recommend a mechanism or forum for the study of the separation of commodity sales (merchant function) from the LDCs' transportation/distribution functions.

11.1.18 This process became known as the Ten Year Market Review. On September 27, 1996 the Board issued its Report on the Ten-Year Market Review in which it stated that it would use a working group followed by a public hearing process to continue its review. The working group is expected to report to the Board by April 30, 1997.

11.1.19 In this proceeding the Utilities proposed:

- the implementation for each Utility of an agent billing and collection service ("ABC Service") similar to that approved for Consumers' Gas in E.B.R.O. 492.

- a change in the displacement provisions for Union's system customers wishing to become direct purchase customers ("the proposed displacement policy");

- a change, for both Centra and Union, in the methodology for calculating the buy/sell reference price from calculations based on avoided costs to market-based calculations ("the proposed market-based buy/sell pricing methodology"); and

- that on March 1 and October 31 each year direct purchase customers of both Utilities be required to balance their actual deliveries against their contracted deliveries ("two point balancing").

11.2 ABC SERVICE

11.2.1 The Companies' proposed ABC Services would enable ABMs to bill their customers directly through Union or Centra. ABMs contract with Union or Centra for bundled T-service, a service in which the Utility transports and delivers to customers gas purchased by the ABMs outside of Ontario and provides any requisite storage and load balancing. Under ABC Service, ABMs, as agents for customers, would set the terms and conditions of gas supply with their customers, and use the Utility's billing system to collect the costs. The pricing arrangements would not be limited to the Utility's buy/sell reference price or necessarily be tied to the Utility's WACOG. The ABMs would be paid by the relevant Utility monthly for the cost of gas supplied to ABC customers, less administrative charges.

11.2.2 The details, in the initial prefilings by the Companies of the proposed ABC Service, were in many respects identical to the Service proposed by Consumers' Gas in E.B.R.O. 492. The Service was described in detail in the E.B.R.O. 492 Decision. The Board in that case approved the proposed ABC Service, subject to a number of conditions designed to ensure consumer awareness and protection. These conditions included the development of a Code of Conduct to be adhered to by those offering ABC Service containing principles of consumer protection and detailing the kind of information that must be provided to consumers. The Board also required that a Customer Information Package ("CIP") be developed to be provided to all utility customers by the LDC, and prohibited the use of negative options to switch existing direct purchase customers to ABC Service.

11.2.3 It was the Companies' view that the level of service fees for ABC Service should not be regulated in order to allow innovation and customization of the fees as new aspects of the service develop. The forecast costs and revenues would, in the Companies' proposal, be included in the cost of service. The proposed fee would be a monthly charge of $0.50 per account, and was designed to cover the marginal costs of maintenance to the billing system, call handling and bad debt expense.

11.2.4 In their supplemental evidence, witnesses for the Companies set out modifications to their original ABC proposals in light of their review of the Board's Decision with Reasons in E.B.R.O. 492. They outlined their specific responses to that Decision as follows:

Code of Conduct/Expectations of Performance

11.2.5 The Board's Decision in E.B.R.O. 492 required an ABC Code of Conduct to be developed by the Direct Purchase Industry Committee ("DPIC"). Union and Centra noted that DPIC is a voluntary organization, with members with a variety of viewpoints, and expressed their concern that DPIC would be unable to reach agreement on a Code and a complaints procedure. In that event, the Companies undertook to make the Code requirements set out by the Board in E.B.R.O. 492 a condition for their ABC Services.

Information/Awareness for Customers

11.2.6 Union and Centra agreed to the requirements set out by the Board in E.B.R.O. 492 and supported the need for a CIP. The Companies' witness suggested that an effective customer awareness package would need to include "a broad based communication plan using multiple forms of media such as : direct mail, newspaper ads, bill inserts, periodic news releases, and phone responses" suggesting the "apportioning [of the costs of such a plan] between ABM's and cost of service."

Conditions to be Met by a Party Making a Pricing Offer

11.2.7 The Companies accepted the conditions, which are to be reflected in the DPIC Code of Conduct, and stated that they would require these conditions in their own Code, should DPIC be unable to reach agreement on the Code.

Recourse for Customer in the Event of a Complaint

11.2.8 If there are difficulties enforcing the DPIC Code's mechanism for complaint resolution, the Companies agreed to "attempt to help the parties resolve the dispute."

11.2.9 The Companies noted that, the Board in E.B.R.O. 492, required the LDC to absorb certain costs of the process of moving customers from a buy/sell arrangement to ABC Service. They further noted that the operational aspects of implementing that Decision are currently being examined by members of DPIC, including Consumers' Gas. Union/Centra are also participating in these discussions, but suggested that costs which will be incurred ought to be tracked in a deferral account, and "borne by the ABMs utilizing the service."

11.2.10 In oral testimony and under cross-examination, witnesses for the Companies expanded on the nature of the communications program that might be required, estimating its cost at $1.5 million. They also expressed the view that adequate price disclosure did not require the Companies to provide a comparable unit price of system gas on the bills sent out to ABC customers, for comparison with the prices being paid under the ABC Service.

11.2.11 A panel of witnesses appearing on behalf of CENGAS supported the development of ABC Service in the Union and Centra areas, stressing that it should be consistent with the service to be offered in the Consumers' Gas franchise area, that the code of conduct and complaints mechanism should be developed by DPIC, and not the Companies, and stated that the extensive information program suggested by the Companies was unnecessary. Under cross-examination, CENGAS witnesses testified that they believed it to be inappropriate to put the utility unit cost of gas on an ABC customer’s bill for the purpose of comparison with the price option they have chosen under ABC Service.

Positions of the Parties

11.2.12 The Companies noted in argument-in-chief that they were participating in the discussions with those parties who were working to implement the Board’s decision on ABC Service in the Consumers' Gas franchise area, and that they were prepared to work with stakeholders “to implement that service in a way that accommodates both the Board’s concerns and the apparent requirements of the marketplace.” The “broad-based communication plan” proposed by the Companies’ witness was “not intended to be in any way definitive.”

11.2.13 Board Staff supported the introduction of ABC Service “as an alternative in the market place and as further development of the direct purchase industry and deregulation”, but noted its concern that appropriate safeguards are necessary to protect vulnerable consumers. It therefore submitted that the same requirements set out in the Board’s decision in E.B.R.O. 492 should guide the implementation of ABC Service in the Centra and Union areas, noting that “it would be much more efficient to have one set of rules for ABC and one form of CIP for all Ontario customers.”

11.2.14 CAC argued that the evidence introduced in this hearing underscored the need for effective consumer protection and educational measures for the provision of the ABC Service. Citing the various promotional brochures which were filed, CAC noted certain failings in these communications with respect to risk and price disclosure, noting, for example, that: the brochures offer price discounts from prices offered in the past by a utility, rather than specific prices; the contracts are "evergreen" (renewable if not cancelled); and the minimum term for some is five years, for others, two years. Some of the contracts give broad powers to ABMs on behalf of consumers, including the assignment of the contracts without the consumers' knowledge or consent, and include such things as naming the ABM "sole and exclusive agent" for other purposes, such as arranging electricity "upon deregulation of electricity supply".

11.2.15 Noting the high level of ignorance of the operation of direct purchase as evidenced by the customer surveys filed in E.B.R.O. 492 and in this case, CAC expressed concerns about the type of obligations purported to be created by the above brochures and agreements on consumers with little or no knowledge of the basic pricing structure or market arrangements for natural gas.

11.2.16 Acknowledging that the Board has no jurisdiction with respect to contracts between the ABMs and customers, CAC suggested that the Board insist on the appropriate information provision in the CIP. In CAC's view, the position of CENGAS, supported by the Companies, that it is not willing to put a comparative utility price on the bill to an ABC customer is "inconsistent with true price disclosure".

11.2.17 In summary, the CAC supported the introduction of ABC Service subject to the same conditions set out by the Board in the E.B.R.O. 492 Decision, with the additional requirements that:

- ! the Utilities, not DPIC, "should be responsible for ensuring that ABMs comply with the requirements of ABC Service" and should be required to report in the next rates case on the operation of ABC Service, including compliance with consumer protection measures; and

- ! the Board should, given consumer ignorance and the risks of abuse, "play a continuing role in monitoring all aspects of the sale of gas, including the activities of ABMs" and, in its decision, "express its concern about the adequate protection of consumer interests in the ABC Service and the need, accordingly for the appropriate legislative changes to ensure the OEB have a continuing role in ensuring that consumer interests are protected."

11.2.18 Direct Energy and PanEnergy supported the introduction of ABC Service, noting that consistency among the franchise areas is "worthwhile." In their view, as experience is gained, users of the service can assess the appropriate level of the service charges based on the costs incurred to service the accounts. They therefore submitted that the Board should approve the proposed service, but require the Utilities to track the costs allocated to providing the service, for review in the next proceeding.

11.2.19 Energy Probe urged the Board to accept the proposed service, to direct the Companies to make the ABC Service as consistent as possible with that to be offered by Consumers' Gas, and to provide to the Board, before program implementation, a detailed explanation of any differences. Energy Probe's only concerns related to costs of implementing the program. It argued that there is no need for the "extensive and expensive" media program described by the Companies' witnesses, and that all general service customers should bear the cost of the modest information package equivalent to that anticipated by the Board in E.B.R.O. 492.

11.2.20 Enron supported the ABC Service, subject to two caveats:

! In Enron's view, the service is a transition or 'stop gap' measure pending more thorough ongoing changes to the market structure being considered in Ten Year Market Review; and

! Assurances must be given to the ABMs that market data made available to the Utilities in providing the billing service will remain confidential. In Enron's view, a code of conduct is needed to govern the relationship between Utilities and their marketing affiliate or affiliates, to ensure that confidential information provided to the Utilities is not shared with competitors of the ABMs who provided it.

11.2.21 IGUA and London GasSave agreed that ABC Service should be made available as soon as possible, complying with the conditions set out in E.B.R.O. 492, but IGUA argued it should be offered as a non-utility service.

11.2.22 NCL did not oppose the ABC Service, although it did oppose the proposal in E.B.R.O. 492. It argued that, until the Board and direct purchasers have had experience with it, the "Board should not take steps which in effect force end users and ABMs to use ABC, for example, by making the buy/sell mechanism impractical."

11.2.23 OCAP submitted that the Board should import the conditions set out in E.B.R.O. 492 into its Decision in this case, and that the Board should take a continuing role in monitoring the impact of ABC, including the response to the CIP.

11.2.24 TCGS supported the Companies' proposed ABC Service on the basis that "substituting a true transportation service for the buy/sell would expose consumers more directly to market forces, and require them to assume direct and meaningful responsibility for their own purchasing decisions". It submitted, however, that it is necessary to be vigilant about consumer protection issues, in case the introduction of the service actually decreases the effectiveness of competition.

11.2.25 In UGSWO's view, the proposed ABC Service might also benefit associations or companies with multiple accounts that have entered into T-service agreements; it submitted that the service "could be used by such organizations to bill the gas commodity directly to individual accounts rather than through the billing systems with Companies or associations." UGSWO therefore supported the proposal subject to the E.B.R.O. 492 requirements being met.

11.3 BOARD FINDINGS ON ABC SERVICE

11.3.1 The Board finds that the Companies' proposed ABC Service is acceptable, provided that the requirements imposed by the Board in E.B.R.O. 492 are met by the Companies. The Board finds that the CIP developed for use in the Consumers' Gas' franchise area would be an adequate form of customer education in the Union/Centra areas, and does not accept that a more elaborate media program as outlined by the Companies' witnesses is required. The Companies should modify the CIP that has been developed only to the extent necessary to make it useable in the Companies' franchise areas.

11.3.2 In requiring the development of an information package for all customers, the Board intends that customers will be made aware that the costs of gas contracted with the ABM are not regulated. The Board is of the view that the provision of gas purchased by an agent for an ABC customer does not constitute the "supply of gas" within the meaning of sub-section 1(1) of the Act. A number of intervenors have urged that the legislation under which the Board obtains its authority be reviewed and updated, and the Board agrees that such a review should be undertaken once the Ten-Year Review has been completed.

11.3.3 In implementing ABC Service, the Board requires that the Utilities satisfy themselves that ABMs have the authority to act for those customers for whom they purport to be agents, and provide, on the first bill for each ABC Service customer, a statement to the effect that the customer is now on ABC Service with the (named) ABM, a suggestion that the customer contact the ABM for additional information, and advice that the customer may, within thirty days of receipt of the bill, advise the Utility and the ABM that the customer does not wish ABC Service and wishes to return either to its previous buy/sell arrangement or to system gas service, as applicable. The name and telephone number of the customer's ABM should appear on all ABC bills.

11.3.4 The Board notes the argument by CAC that appropriate price disclosure should include the provision of comparative prices charged for system gas on the bills received by ABC Service customers. The Board finds, however, that it might be misleading to provide a unit cost of system gas that cannot take into account future adjustments through charges or refunds of gas cost price differences resulting, for example, from PGVA imbalances. In the circumstances, the Board relies on the development of the "price transparency by means of regular dissemination of current pricing information through joint publication in widely available media" agreed to by the parties and the utility in E.B.R.O. 492 to provide the disclosure in as fair a manner as possible to consumers who must be able to make informed choices with respect to fulfilling their requirements for natural gas service.

11.3.5 Included in the Board's requirements for ABC Service, as in the E.B.R.O. 492 Decision is the requirement that the Companies provide detailed information on the costing and pricing of this service to the Board at the next rates hearings. In addition, the Board notes that a portion of the $0.50 monthly charge is derived from the provision for bad debts. The Board is not persuaded that it is either necessary or appropriate for the Companies to provide such coverage for the ABC Service customers, or their ABMs and directs the Companies to file information at the next rates cases on which the Board may determine this issue, and ensure that the costs of the service are appropriately recovered.

11.4 THE PROPOSED DIRECT PURCHASE DISPLACEMENT POLICY

11.4.1 While Union stated that its proposed direct purchase displacement policy would apply to all system customers who become direct purchase customers, the focus of the evidence and argument was on system customers who become buy/sell customers.

11.4.2 Under the proposed displacement policy (Option 6 below), TCPL capacity would be made available to system customers who become direct purchase customers in the same proportion that TCPL capacity represents of Union's current portfolio of transportation capacity for its system customers' gas supplies. The proportion would be updated quarterly to reflect Union's then current portfolio of transportation for its system customers. For 1997 Union forecast that it could make available 65% of a new direct purchase customer's capacity needs through displacement of firm TCPL capacity and the new direct purchase customer would then be responsible for finding transportation capacity for the remaining 35%. Existing direct purchase customers' arrangements would not be impacted by the proposed policy.

11.4.3 Prior to informing customers of its proposed direct purchase displacement policy, Union had sent a letter dated July 24, 1996 to all DPIC members, all E.B.R.O. 493/494 Intervenors and the Board inviting the addressees to a meeting on August 1, 1996 to discuss current direct purchase displacement provisions. In the letter Union provided the following options for a displacement policy.

1. *Status quo*
2. *Stop doing any further DP* [direct purchase] *until incremental TCPL capacity is available*
3. *Facilitate DP but only if the ABM//Customer provides its own pipeline capacity*
4. *Continue to serve DP using TCPL* [capacity] *but allocate excess gas costs in PGVA to all franchise customers* ("Option 4")
5. *Continue to displace (status quo) but charge DP customer the market price for TCPL capacity*
6. *TCPL Proportionate Capacity Allocation* ("Option 6")

11.4.4 At the August 1, 1996 meeting two other options were proposed:

7. *Clawback and reallocation of DP allocated capacity* ("Option 7" or "the Clawback Option")
8. *U.S. Buy/Sell*

11.4.5 Union indicated that 10-12 parties had preferred the status quo and one party preferred Option 7. When a "show of hands" was requested on the assumption that the status quo was eliminated, one party voted for Option 3, four for Option 6 and one for Option 7.

11.4.6 In a letter dated August 19, 1996 Union informed interested parties that Union would be implementing its proposed direct purchase displacement policy, Option 6, as of October 1, 1996 and that Union would continue to accept requests for direct purchase displacements under the existing policy until August 26, 1996.

11.4.7 On August 30, 1996 Union filed updated evidence setting out its proposed direct purchase displacement policy which was to become effective October 1, 1996.

11.4.8 On September 3, 1996 CENGAS filed a Motion asking the Board to issue an order directing Union to continue to accept and process from August 26, 1996 until December 31, 1997 any application from a customer or its agent to enter into a buy/sell arrangement with Union, subject only to such applications complying with the usual terms and conditions in force prior to August 26, 1996.

11.4.9 On October 1, 1996 CENGAS filed an amended Motion in which it requested, in addition to the relief set out above, an interim order of the Board directing Union to refrain from implementing the Company's proposed direct purchase displacement policy until the Board had disposed of the Motion.

11.4.10 The Board heard the CENGAS Motion at the beginning of the hearing. It was the testimony of CENGAS' witnesses that if Union's proposed direct purchase displacement policy were put into effect, it would effectively end any marketing of buy/sell in Union's area until the Board approved ABC Service.

11.4.11 The Board reserved its decision on the CENGAS Motion until it had heard all the evidence and argument on direct purchase matters.

11.4.12 Union informed the Board, during the hearing of argument on the CENGAS Motion, that it would not process new buy/sell contracts until the Board had made its decision on the proposed direct purchase displacement policy. However, if a customer were willing to accept the proposed policy, Union would process the contract. As of November, 1996 two customers, one an affiliate of Union, had accepted the proposed direct purchase displacement policy.

11.4.13 The Board sets out its Decision on the CENGAS Motion below, following its Findings on the Proposed Direct Purchase Displacement Policy.

Union's Evidence

11.4.14 Union justified its proposed direct purchase displacement policy on the basis that because firm capacity on TCPL is limited, released capacity is trading in the secondary markets at a premium to the NEB approved tolls and therefore, new direct purchase customers are displacing Union's lowest cost firm western Canadian supplies which Union uses to supply its firm system customers. The result is an increase in Union's WACOG which is passed on to customers through Union's sales rates.

11.4.15 During the hearing Union forecast that the negative gas cost impact on system customers in 1996 of 150,000 10^3m^3 being displaced by direct purchase would be \$3 million. Union subsequently amended this forecast stating that there would not be any impact in 1996 because of offsetting credits in Union's PGVA. For 1997 Union forecast that a further 50,000 system customers would become direct purchase customers resulting in a negative gas cost impact on remaining system customers of \$1.8 million.

11.4.16 In addition, as an added justification of its proposed direct purchase displacement policy, Union expressed concern that eventually all of its firm transportation capacity may be displaced. In that event, the remaining firm system customers would not have an available source of firm transportation and would have to rely on spot gas, delivered gas and U.S. supplies.

11.4.17 In its Motion, CENGAS filed a table setting out the relationship of Union's buy/sell prices to the unit cost of its other gas supplies since Fiscal 1991. Union amended the table to more accurately reflect the cost. The amended table is set out in Table 11.1.