RP-2003-0063
EB-2003-0087
EB-2003-0097

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

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

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APPENDICES

1. THE APPLICATION AND THE PROCEEDING

1.1 THE APPLICATION AND BACKGROUND

Union Gas Limited ("Union" or the "Applicant" or the "Company" or the "Utility") filed an application dated May 2, 2003 (the "Application"), with the Ontario Energy Board (the "Board") pursuant to section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (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 gas, effective for the year commencing January 1, 2004. The Board assigned file number RP-2003-0063 to the Application. The Board issued a Notice of Application dated May 22, 2003, with a letter containing directions for service.

Union filed a cost of service ("COS") application which will be used to establish rates for fiscal 2004 and would also serve as the base for Union's rate applications for subsequent years, if it files a Performance Based Regulation ("PBR") methodology for its 2005 rates. In the RP-1999-0017 Decision, the Board had approved a three-year trial PBR plan for years commencing January 1, 2001, 2002, and 2003.

1.2 THE PROCEEDING

Union filed evidence in support of the proposed 2004 revenue requirement, described as Phase I evidence, on May 23, 2003. Union undertook to file evidence in support of its 2004 cost allocation and rate design proposals, described as Phase II evidence, on or before June 20, 2003. The Board assigned file numbers RP-2003-0063\EB-2003-0087 and RP-2003-0063\EB-2003-0097 respectively to the two phases of the Application.

By letter dated June 9, 2003, Union invited intervenors to attend a stakeholder consultation meeting at the Board's office on Wednesday, June 18, 2003. At the meeting, Union outlined its prefiled evidence and Board staff advised parties of the proposed schedule for the proceeding.

On June 20, 2003, the Board issued Procedural Order No. 1, including a schedule for the proceeding and setting out dates as follows: an Issues/Stakeholder Conference to be held on July 8, 2003; an Issues Day, July 11, 2003; interrogatories on the Applicant's evidence, July 24, 2003; interrogatory responses, August 7, 2003; filing of intervenor evidence, August 14, 2003; interrogatories on intervenor evidence, August 21, 2003; interrogatory responses, August 28, 2003; submission of intervenors' position papers for the Settlement Conference, September 2, 2003; a Settlement Conference, September 4 - 12, 2003; and submission of any proposed Settlement Agreement to the Board no later than September 17, 2003.

Parties met to discuss a proposed issues list at an issues/stakeholder conference held on July 8, 2003.

The proposed issues list, containing twelve contested issues, was reviewed by the Board on Issues Day, July 11, 2003. After the Board heard parties' submissions on the contested issues, it rendered its decision in respect of the proposed issues list. On July 16, 2003, the Board issued Procedural Order No. 2 containing the approved Issues List.

On July 24, 2003, Union wrote to the intervenors indicating Union's "...desire to negotiate a potential multi-year pricing arrangement with intervenors. This potential arrangement could replace both the 2004 Cost of Service outcome and the PBR proposal for 2005 and beyond." The letter indicated that Union would first attempt to scope a framework for the multi-year arrangement with the Consumers' Association of Canada ("CAC") and Industrial Gas Users Association ("IGUA"). All intervenors were invited to a meeting held in Toronto on August 14, 2003 to discuss and review Union's initiative. Union indicated that it would continue to meet with CAC and IGUA over the balance of August to discuss the parameters of a multi-year pricing arrangement.

By letter dated August 12, 2003, the City of Kitchener (‘Kitchener”) requested a one day extension to the filing of intervenor evidence, due to the incompleteness of some interrogatory responses and due to Union’s “parallel” stakeholder process.

By letter dated August 13, 2003, London Property Management Association and the Wholesale Gas Purchasers Service Group jointly requested that the Board delay the beginning of the Settlement Conference from Thursday, September 4, 2003 to Monday, September 8, 2003.

The Board issued Procedural Order No. 3 on August 18, 2003, in which it acceded to the requests by Kitchener, the London Property Management Association and the Wholesale Gas Purchasers Service Group to extend the filing dates.

1.3 THE SETTLEMENT CONFERENCE

Board staff provided a summary document of the major issues to all parties prior to the commencement of the Settlement Conference on September 8, 2003.

Also, prior to the commencement of the Settlement Conference, Board staff received position papers from the following parties: Energy Probe, Vulnerable Energy Consumers’ Coalition, Wholesale Gas Service Purchasers Group, London Property Management Association, Canadian Manufacturers and Exporters Inc., the Coalition for Efficient Energy Distribution, Consumers’ Association of Canada, Industrial Gas Users Association, the City of Kitchener, the Green Energy Coalition, Pollution Probe, Union Energy Inc., Ontario Energy Savings Corporation, Superior Energy Management, Northern Cross Energy Limited, ECNG Inc., Ontario Association Of School Business Officials, Ontario Public School Board’s Association and Citysyn.

The Settlement Conference, attended by the Applicant, intervenors and Board staff, commenced on September 8, 2003, with Ms. Cindy Dymond acting as the facilitator.

Negotiations concluded on September 17, 2003. Union prepared a draft settlement proposal which was submitted to the Board on September 22, 2003. Parties reached a complete settlement on only three issues. A further ten issues were settled by parties either mutually agreeing to reduce the scope of the issue or not oppose Union's proposal on these issues. Approximately seventy issues remained unresolved.

Union made an oral presentation of the settlement proposal to the Board on October 3, 2003, following which the Board accepted it as proposed. The Settlement Agreement is attached as Appendix C of this decision.

The Board acknowledges the efforts of the participants in the Settlement Conference, especially the facilitator Ms. Cindy Dymond.

1.4 THE HEARING

The oral hearing commenced on October 6, 2003, and continued until November 10, 2003.

Union's oral argument-in-chief was submitted on November 10, 2003. Intervenors' arguments were filed by November 27, 2003, and Union's reply argument on December 11, 2003.

1.5 PARTICIPANTS AND THEIR REPRESENTATIVES

Gas Ontario Inc.,Coral Energy Canada Limited, The City of Greater Sudbury , The Federation of Northern Municipalities and TransAlta Energy Corporation applied for status as late intervenors. Union raised no objection to the requests, subject to the parties accepting the record in the proceeding. The Board accepted the applicants as late intervenors. Both Coral Energy Canada Limited and TransAlta Energy Corporation indicated that they wished to file evidence.

Below is a list of participants and their representatives that participated actively, through the settlement conference process, leading evidence or cross-examining at the oral hearing, or by filing argument.

Union Gas Limited	Michael Penny
	Crawford Smith
	Marcel Reghelini
	Bryan Goulden
Board Counsel and Staff	Pat Moran
	Martin Davies
	Chris Mackie
	James Wightman
	Neil Yeung
Canadian Manufacturers & Exporters Inc. (“CME”)	Mimi Singh
	Malcolm Rowan
The City of Greater Sudbury (“Sudbury”)	Peter Scully
Coalition for Efficient Energy Distribution (“CEED”)	George Vegh
Consumers’ Association of Canada (“CAC”)	Robert Warren
	Julie Girvan
Coral Energy Canada Limited ("Coral Energy”)	David Brown
The Corporation of the City of Kitchener (“Kitchener”)	Alick Ryder
	Dwayne Quinn
Distributed Energy Association (“Distributed”)	Brian Dingwall
Enbridge Gas Distribution Inc. (“EGDI”)	Robert Rowe
Energy Probe	Brian Dingwall
	Tom Adams
	David MacIntosh

ECNG Inc.	Bill Killeen
Energy Objective Ltd.	Philip Walsh
The Federation of Northern Municipalities (‘FONOM”)	Peter Scully
Green Energy Coalition (“GEC”)	David Poch
The Heating, Ventilation, Air Conditioning Contractors Coalition Inc. (“HVAC Coalition”)	Brian Dingwall
Industrial Gas Users Association (“IGUA”)	Peter Thompson
	Vince DeRose
London Property Management Association (“LPMA”)	Randy Aiken
The Municipality of the City of Timmins (“Timmins”)	Peter Scully
Northern Cross Energy Limited (“Northern Cross Energy”)	David R. Thompson
Ontario Association of Physical Plant Administrators (“OAPPA”)	Valerie Young
Ontario Association of School Business Officials (“Schools”)	Thomas Brett
Ontario Energy Savings Corporation (“OES”)	George Vegh
Ontario Public School Board’s Association (“School Boards”)	Jay Shepherd
Ontario Power Generation Inc. (“OPG”)	Angela Wong
Pollution Probe	Murray Klippenstein
	Jack Gibbons
Superior Energy Management	George Vegh
TransAlta Energy Corporation (“TransAlta”)	George Vegh
TransCanada PipeLines Limited (“TCPL”)	Tibor Haynal
Vulnerable Energy Consumers’ Coalition (“VECC”)	Michael Janigan
	Joyce Poon
Union Energy Inc.	George Vegh

Wholesale Gas Service Purchasers Group ("WGSPG")	Randy Aiken

The following submitted letters of comment:

Wayne B. Tod, City Clerk, City of Belleville	Letter dated June 18, 2003
Bent Sangill	Letter dated June 25, 2003
Walter Sans	Letter dated June 28, 2003
Bryce Stacey	Letter dated June 19, 2003
Raymond Gunsolus	Letter dated June 18, 2003
Euro Narduzzi	Letter dated June 11, 2003
Elizabeth Archer	E-mail, dated June 5, 2003
Norm Dallaire	E-mail, dated June 3, 2003
James Roberts	Letter dated June 19, 2003
James Hawken, Mayor, Town of New Liskeard	Letter dated June 5, 2003
Gerry & Adeline Cadotte	Letter received June 12, 2003
Vic Janulis, Norfolk Federation of Agriculture	Letter dated June 5, 2003
Claude Laflamme, CAO/Clerk Town of Hearst	Letter dated July 31, 2003

1.6 WITNESSES

The following Union employees appeared as witnesses:

Wayne Andrews	Manager, Customer Support
Richard Birmingham	Senior Vice-President , Regulatory Affairs & Marketing
Bohdan Bodnar	Vice-President, Human Resources
Wendie Brodie Lumley	Manager, Plant & General Accounting
Michael Broeders	Manager, Reporting & Forecasts

David Dent	Manager, Gas Supply
Patricia Elliott	Director, Accounting
Chuck Farmer	Manager, Market Planning & Evaluation
William Fay	Manager, Underground Storage
Allan Fogwill	Manager, Market Knowledge
Lynn Galbraith	Manager, Lines of Business
Paul Gardiner	Manager, Demand Forecasts & Analysis
Dennis Hebert	Director, Taxation Services
Ken Horner	Manager, Revenue & Gas Accounting
Larry Hyatt	Manager, System Planning
Mark Isherwood	Director, Acquisitions
Mark Kitchen	Manager, Rates & Pricing
Jim Laforet	Manager, Affiliate Relations
Pat McMahon	Manager, Product & Services Costing
Don Newbury	Manager, Integrated Supply Planning
Michael Packer	Manager, Regulatory Initiatives
Steve Poredos	Director, Capacity Management
Bruce Rogers	Director, Sales & Marketing
Jim Sanders	Manager of Operations Engineering
Paul Shervill	Director, Channel Management
Dave Simpson	Manager, Asset Acquisition
Sarah VanDer Paelt	Manager, Product & Service Development

Union also called the following witnesses:

David Neilly	Senior Consultant, Towers Perrin

Steven Root	President and Chief Executive Officer, Weather Bank Inc.
John Snell	Principal, Risk Management Inc.
Andrew Weaver	Professor, University of Victoria
Ashley Witts	Principal, Towers Perrin

Kitchener called the following witness:

Dwayne Quinn	Director of Utilities, Kitchener

Coral Energy called the following witnesses:

John Todd	President, Elenchus Research Associates
Paula Zarnett	Barker, Dunn and Rossi
Greg Baden	Vice President, Power, Coral Energy

Pollution Probe called GEC's witness, Mr. Chris Neme of Vermont Energy Investment Corporation.

By agreement between the parties, the following intervenors were not required to present witnesses in support of their evidence:

Energy Objective Ltd.

GEC

WGSPG

Northern Cross Energy

TransAlta

1.7 SUBMISSIONS AND EXHIBITS

Copies of the evidence, exhibits, arguments, and a transcript of the proceeding are available for review at the Board's offices.

The Board has considered the evidence, submissions and arguments in the proceeding, but has summarized the evidence and the positions of the parties only to the extent necessary to provide context for its findings.

The Board, with industry participation, has developed standards and processes for the electronic regulatory filing ("ERF") of evidence, submissions of parties, Board orders and decisions. This Decision with Reasons will be available in ERF form shortly after initial copies are issued in hard copy. The ERF version will have the same text and numbered headings as the initial hard copy, but may be formatted differently.

2. POLICY ISSUES

2.1 RISK MANAGEMENT INCLUDING STUDY AND RISK MANAGEMENT ACTIVITIES AND APPROACH

Union's Request

Union is seeking Board acknowledgment that its risk management program is appropriate and that the proposed changes to the program are reasonable.

Background

As part of the settlement agreement in its last rate setting proceeding (RP-2001-0029), Union agreed to engage an independent consultant to conduct an assessment of its commodity risk management plan. Union selected Risk Management Inc. ("RMI") to undertake this assessment.

RMI's review focused on the extent to which Union's policies were consistent with industry standards; whether appropriate goals and objectives were set; and whether Union was meeting its risk management goals and objectives. In addition to reviewing the current program, RMI set out proposals for improving the Company's risk management plan.

RMI concluded that the objectives that Union had in place were appropriate and in line with those of similarly regulated utilities. They also noted that Union's oversight committee, established to maintain shared accountability, provided internal controls and mitigated the potential abuse of power stemming from any one executive or department. RMI found that the plan had sufficient checks and balances in place between the gas supply and finance departments for transaction, verification, and program activity reporting. Where actual transaction activity was concerned, RMI reported that:

> [it] believes that Union Gas meets industry standards in its use of statistical and portfolio analysis...Union Gas can be comfortable in the fact that it has minimized volatility and provided reasonable value to the ratepayer during a period of unprecedented volatility for natural gas products.

Union's Position

The RMI Report provided eleven recommendations to improve Union's risk management plan. Union gave its unqualified agreement to eight of these:

1. re-state the objective "Achieve A Market Responsive Price" to "Provide Reasonable Value Through A Diversified Portfolio";

2. add the objective "Minimize Exposure to Counterparty Credit Risk";

3. add market flexibility to the program through the application of Hedge Committee-approved price and volume strategy parameters;

4. clearly indicate that a segregation of duties exists between the gas transaction function and the Risk Manager oversight role by re-titling the position of "Risk Specialist" to "Hedge Specialist/Analyst" and designate the Risk Manager function as falling outside of the Gas Supply function;

5. streamline the oversight control for physical and financial risk by combining the Commodity Risk Management Program with the Physical Procurement Program;

6. expand the type of financial instruments approved for hedge execution to include selling calls and buying puts for both exchange-traded and Over-the-Counter (OTC) products;

7. increase emphasis on the use of statistical analysis for hedging decisions and maintain a disciplined implementation plan; and

8. provide open communication to the OEB on policy and procedural updates to the program. Union subsequently agreed, in response to an intervenor interrogatory, to expand this recommendation to encompass intervenors, as well as the Board.

Union also agreed with the recommendation by RMI to have a committee approve broad price and time parameters and allow the gas supply personnel, or hedgers, to work from these guidelines.

Union gave qualified agreement to two other recommendations.

1. Allow for a longer-term hedge perspective by re-defining the acceptable “Hedgeable Volumes” as a certain approved percentage of forecasted expected future demand and to determine the acceptable longer-term horizon and associated authorized percentages.

Union characterized this recommendation as allowing it to buy for future years when prices are particularly low. Union stated that while it was in agreement with this recommendation, long term planning must take into account the flexibility required to facilitate future direct purchase activity and the credit risk associated with long-term positions.

2. Add flexibility to the hedge program by expanding approved instruments to include New York Mercantile Exchange (“NYMEX”) products.

Union acknowledged that the use of an exchange-traded product, such as NYMEX instruments, mitigates credit risk exposure and maximizes transactional flexibility. Union proposed to include such instruments in the commodity risk program. However, Union stated its preference to continue to use the OTC market at this time. Union's current portfolio split is approximately 25:75 between NYMEX and OTC hedging instruments.

Union was not in agreement with one recommendation, which was to add an annual program review for any needed updates to the Hedge Committee responsibilities. Union argued that review of the program should be done when necessary, rather than on an annual basis.

Union stated that the adoption of the RMI recommendations would enhance its risk management program, while not significantly changing its overall risk level. Union also stated that the adoption of the RMI proposals would provide the ratepayer with increased rate stability.

Union also stated that the RMI Report addressed the issue of whether it should be engaging in risk management at all. RMI's report showed that 80 percent of the commissions regulating natural gas utilities allow commodity risk management as a tool to stabilize natural gas prices and also allow the utilities to fully recover the costs of their risk management activities. Union noted the testimony of RMI principal, Mr. Snell who testified:

> The concept of not hedging is potentially the most risky position that one might take because you are assuming the total risk of the market in anticipation of trying to get the lowest possible price. And there is, again, a risk reward to the marketplace that makes that extremely risky. You have no price stability, you have no hedge against volatility, and it is statistically speaking, a very risky thing to do.

Union urged caution in determining the appropriate cost for a risk management program since such assessments are entirely dependent on the time period examined and its place in any cycle of natural gas prices. However, Union stated that when it examined the past five and a half years it found that its commodity costs have been just below the market, but only half as volatile as the market, which in Union's view is consistent with the objective of the program.

Union stated that concerns that long term hedging and the use of puts and calls adds unnecessary complexity to the risk management process are unfounded. Union maintained that the more hedging options that are available to Union, the more choices Union would have to manage commodity risk.

Union also responded to the concerns of some parties that its hedging plans and risk management policies should be provided to parties when changes occur. It noted that the role of its internal Commodity Risk Committee is to ensure that Union follows stated risk management policies, and to oversee transactions on an ongoing basis. It further asserted that such a requirement for the provision of information would represent inappropriate micro-management of the Utility. Union stated that when proposing deferral account disposition, it would file its risk management policies and all relevant data to enable an assessment of the cost and compliance with the policies.

Union disagreed with the contention of some intervenors that commodity risk management interferes with the competitive gas commodity market. It noted that risk management tools are also available to gas marketers.

Union submitted that risk management was both an appropriate and prudent practice as it is a widely-recognized method of managing price volatility. Union added that its risk management program had been demonstrated to be working effectively by an independent external consultant, and that its total costs were well within a band of acceptable levels of costs that are experienced in the industry. The adoption of RMI's recommendations as proposed by Union would enhance the program.

Board Findings

Union is seeking Board acknowledgement that its risk management program is appropriate and that the proposed changes to the program are reasonable.

The Board must consider five issues: (1) are the objectives of the current program reasonable; (2) does the current program provide value to ratepayers (3) is a commodity risk management program anti-competitive; (4) do the proposed changes provide an opportunity for improvement; (5) should the utility be required to do more or better program reporting?

Recent volatility in the gas markets has put an increased emphasis on the issue of commodity price volatility. The evidence presented by Union indicates moderate success from past practices. The Board notes that many parties, such as CAC and VECC and gas marketers like OESC, Superior Energy Management and Union Energy supported the continuation of the program.

While the Board does not accept the arguments raised by CME and Energy Probe that Union's commodity risk management program is without benefit, it does agree that such benefits are difficult to measure. The Board believes that such issues are better studied in broader policy forums.

Some intervenors argued that the proposed changes may be anti-competitive to the extent that they increase the degree of smoothing of the price volatility experienced by customers, thereby reducing the attractiveness of contracts offered to customers by marketers that are designed to achieve the same purpose. The Board is unconvinced that Union's risk management program inhibits competitive commodity markets or that such programs are inherently anti-competitive. Hedging activities are available to marketers as well. The Board is unclear as to why a risk managed quarterly price with adjusted variances is any more or less anti-competitive than a non-risk managed price. No price currently offered to Ontario residential or small general service customers is entirely representative of the spot or forward natural gas markets in North America.

The Board notes the concerns expressed about the inherent complexity of programs of this kind, but is not convinced Union's proposed changes add materially to the program's complexity. The changes proposed by RMI and accepted by Union are unlikely to diminish the capacity of the current program and offer the opportunity for marginal improvements. To the extent that intervenors have significant concerns about the operation of Union's risk management program, it is open to them in future proceedings to bring expert evidence recommending appropriate changes to the program.

The Board notes that LPMA and VECC supported the risk management program, but argued that there was a need for increased reporting requirements. This position was characterized by Union as leading to unnecessary and inappropriate micro-management. The Board believes that Union's commitment to file an updated risk management policy, and at the time of deferral account disposition to provide all relevant data for an assessment of the cost impacts and compliance with the policy is sufficient to deal with these concerns.

The Board finds that Union's risk management program does provide value to ratepayers and is, therefore, appropriate, and that the specific changes Union is proposing to implement in the 2004 rate year are reasonable and provide an opportunity to enhance the value of the program.

2.2 WEATHER NORMALIZATION

Union's Request

Union proposes to change its weather normalization methodology and to recover the cost consequences in its rates. This proposal was supported by written evidence produced for Union by Weather Bank Inc (WB) and by Dr. Andrew Weaver, a professor of climatology at the University of Victoria.

Background

Normal weather is defined in terms of heating degree days ("HDD"), calculated on the variances in daily temperatures below 18° C. For example, if the mean daily temperature is 11°C, there are 18 - 11 = 7 HDDs on that day. If the mean daily temperature is 18° C or higher, there are no HDDs.

Weather normalization is used in forecasting demand for the general service classes (M2, R1 and R10), storage and transportation allocations, gas supply planning, and rate design. Weather normalization is also used to estimate average use per customer, which, when multiplied by the forecast number of customers, yields a demand forecast. Although weather normalization is not used directly to forecast demand for other classes, it can have impacts on other rate classes by affecting load balancing costs.

Union has historically used a 30-year rolling average method. In the RP-2002-0130 proceeding respecting 2003 rates, Union proposed to introduce a twenty-year trend methodology similar to what it was already using for distribution system planning and its gas supply portfolio. The impact of extending its use to ratemaking would have been to increase the revenue requirement to be captured in 2003 rates by an extra $13.7 million. At the time, Union was under a three-year trial PBR plan and sought to make this change as a non-routine adjustment. The PBR plan had been established on the basis of the existing weather normalization methodology. The Board denied Union's application on the basis that the weather risk was to be managed by Union as part of its PBR plan, and it was not appropriate to effect a change of this magnitude in the course of the PBR period.

Union's Position

Union's evidence states that, based on data from 1985 to 2000, the 30-year average weather normalization methodology consistently overestimates the heating demand by customers by about 7.6%. Mr. Fogwill of Union testified that the impact of a 1% variance in HDDs is about $3.0 million in annual delivery revenues.

Union argued that the 30-year average method assumed a static long run climatic condition and that this assumption was invalid. It noted that over the last 17 years, the method over-forecast HDDs fourteen times, and under-forecast HDDs only three times. Union cited Dr. Weaver's evidence in respect of climate change and global warming in support of its contention that variations were no longer symmetrical around the weather normal estimate.

In addition, Union stated that "... the yearly variability in temperature is increasing, with the standard deviation of 166 HDDs over the period 1956-1985 period increasing to 310 HDDs over the period 1972-2001. Union stated that its consultant, WB, agreed with Dr. Weaver that global warming was occurring. WB also supported Union's claim that volatility was increasing, noting an increase in the frequency of weather events such as El Nino and La Nina.

Dr. Weaver stated that there was an increase in global average temperature of approximately 0.6 degrees Centigrade (+/- 2°) over the twentieth century. He stated the warming trend occurred during two periods, 1901-1945 and 1976-2000 and were separated by a cooling period between 1945-1976. Union stated that 0.6 degrees per century corresponded to 1.6 HDDs per year. Dr. Weaver gave an estimate of a global average temperature increase of 2°C, but qualified this figure as it applies to Ontario, due to the amplification effect of Ontario geography.

Mr. Root of WB testified that in his experience extreme weather events had become much more common over the last 20 years. He suggested that use of the 20-year trend method would have the effect of mitigating the volatility associated with such extreme weather.

Union listed five objectives that its proposed normalization method was assessed against:

1. symmetry – actual HDDs are expected to vary positively and negatively equally with respect to the forecast HDDs;

2. accuracy – over time the variance between actual and normal HDDs should be minimized;

3. stability – the year over year normalized HDD estimate should not vary significantly when measured using standard deviation;

4. sustainability – the method should not require significant amendments in the near future; and

5. simplicity – the method should be easy to use.

The 20 year trend methodology uses data from twelve Environment Canada weather stations in Union's franchise area. The data is weighted by the throughput volumes in the region associated with each weather station. Union then applied ordinary least squares regression analysis to find the best fit to the weighted HDD.

Union ranked seven weather normalization methods by weighting and applying the above five objectives. The weightings applied by Union were on a scale from 1 to 3 as follows:

1. symmetry was given a weight of 3,
2. accuracy was given a weight of 2, and
3. stability, sustainability, and simplicity were given a weight of 1.

Based on these measures, Union ranked the methods in order, from best to worst, as follows: 20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Union proposed the 20-year trend method rather than the 20-year trend with forecast information method, arguing that the latter was far more complex and that it relied upon a third party's proprietary model and therefore might not be sustainable.

Union stated that the rate impact of adopting the new method would be an increase of $20.4 million in the revenue requirement which would be allocated to the M2, R01, and R10 general service classes only. These impacts resulted from an approximately 3.9% deviation between the 30-year weather average and the proposed 20-year trend weather normalization methodologies. Union proposed to allocate the revenue impacts only to the general service classes because these are the only classes for which Union forecasts demand using weather normalization.

Union's witness testified that other than EGDI, whose weather normalization methodology includes a trending component and a moving average component, no other Canadian utility uses a trend method for this purpose. Further, Union was unable to cite any U.S. gas utility that uses a 20-year trend method.

Union noted that Environment Canada, the U.S. Weather Service, and the World Meteorological Organization all used a 30-year average weather normalization methodology. Dr. Weaver was unaware of any national or international meteorological organization that has changed from a 30-year average to a 20-year trend method, but he pointed out that those groups use the methodology to define a reference value and not as an indicator of the rate at which the reference is changing.

Although Union agreed that the data in evidence showed increasing variability over time, i.e., the data may exhibit heteroscedasticity, Union stated that it had not statistically tested for heteroscedasticity. Union also stated that the data it was relying on was time series data whose mean and variance were changing over time. The data were non-stationary and the validity of standard statistical tests was in question if the data were not stationary.

Board Findings

The Board is asked to approve a change in the weather normalization methodology that is applied to M2, R1 and R10 customer class forecast volumes. Union proposes to apply the 20 year trend methodology currently used to allocate upstream transportation and storage to unbundled customers.

The five objectives and associated weights proposed by Union are a good starting point for establishing a proper weather normalization methodology. The issue for the Board to consider is whether the 20 year trend methodology is a superior forecasting tool than the current 30 year moving average. The impetus to change methodologies is the hypothesis, supported by the evidence of Dr. Weaver, of a global warming trend.

Dr. Weaver's evidence does not support any particular weather normalization method. A number of parties argued for continuation of the 30 year methodology. LPMA and IGUA criticized the statistical analysis done by Union and argued for the continuation of the current practice, or a 20 year method with various proposed revenue adjustment mechanisms. Many parties pointed out that the 20 year proposed methodology would result in a net increase in rates.

IGUA and FONOM argued for a phasing in of any change in methodology. Union rejected this proposal and claimed that this would result in it failing to recover its costs, except during colder than normal weather.

Ratepayers are at risk for unutilized demand charges if the methodology overforecasts HDDs, but the ratepayers are also at risk for the cost of increased winter spot purchases if the methodology underforecasts HDDs.

The Board is concerned with the lack of clarity with respect to the statistical evidence. A number of parties explored whether an estimator derived from ordinary least squares was more or less efficient than using a more sophisticated regression technique. Union's inability to respond clearly is of concern, especially given the large impact that the proposed change in methodology has on its revenue requirement.

Both the 20-year trend and the 30-year average normalization methodologies have advantages in their application. The 20-year trend may track more through the middle of the data and will respond more quickly to changes in short-run trends, but will be more volatile. The 30-year average will respond more slowly to changes but it will be less volatile.

Union was unable to demonstrate that its proposal provided a clear and unambiguous improvement over the 30 year methodology. Nor is the Board convinced that the cited case: *Hemlock Valley Electrical Association* v. *British Columbia Utilities Commission* provides any precedent as to whether it is open to the Board in this case to choose a phased in approach. The OEB Act gives the Board clear authority to adopt any methodology it considers appropriate when setting rates.

In order to test the suitability of changing the normalization methodology, and in consideration of the principle of minimizing rate shock, the Board will allow Union, for 2004, to forecast HDDs based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast respectively. For each year thereafter, the Board will consider 5% declines and inclines to the weighting of the 30 year and 20 year methodology respectively until such time as a 50:50 weighting is in place.

With respect to operational planning, the Board directs Union to use the same forecast for operations planning as is used all other purposes. The Board also directs Union to report on the outcomes of using the hybrid model annually.

2.3 AFFILIATE RELATIONS

Union's Request

Union seeks to recover in rates the costs it incurs as a result of its shared services arrangements with its affiliates. These costs are $28.7 million in total.

Background

Duke Energy Corporation ("Duke") completed the purchase of Westcoast Energy Inc. ("WEI"), the parent company of Union, in March 2002. Following this transaction, Union became a participant in Duke's shared services business model. The use of this model results in the sharing of a broad range of senior management and support services across Duke's many business units, creating inter-company transactions between the Duke business units as they pay for services received, and charge for services provided to other units.

Union has previously shared services with affiliated companies through the WEI Corporate Centre. Under the Duke shared services business model, to which it is now subject, the WEI Corporate Centre is no longer the only, nor even the primary, provider of shared services to Union.

There are now 24 activities being performed by or for Union on a shared services basis. Union provided a listing of the operational and functional groups that are operating under the shared services structure, and attempted to identify for each of these groups the benefits to Union of procuring the activities on a shared services basis.

Under the Duke shared services business model, Union would continue to provide services to affiliated companies in 2004. As in the past, these outbound services would be provided using staff and assets primarily required to support the regulated business. The affiliates receiving services from Union are:

1. BC Pipeline and Field Services;
2. Market Hub Partners Limited Partnership ("MHP");
3. Pacific Northern Gas Ltd.;
4. St Clair Pipelines Limited Partnership;
5. St. Clair Pipelines (1996) Ltd.;
6. Sulphur Products Division;
7. Union Gas Power Limited Partnership;
8. Westcoast Energy International Inc.;
9. Westcoast Gas Services Inc., and
10. Westcoast Power Inc.

Union stated that it provides services to these affiliates at its fully loaded cost, which is a cost-based price that is the sum of the direct costs, such as employee salaries and other expenditures incurred in providing the service, and the indirect costs, such as payroll benefits, the cost of assets used, and a return on invested capital, that are related to the direct costs. Union stated that the majority of these costs would still be incurred, whether or not the affiliates requested such services and would be fully borne by Union.

Union also noted that under the Duke shared services business model, it would continue to receive services from affiliated companies in 2004. Union stated that these services would be provided to Union at a “cost-based” price. In Union’s view this would be consistent with the Board’s recent interpretation of the requirements of the Affiliate Relationships Code (“ARC”).

The services which Union receives from affiliated companies fall into three categories:

1. business services, comprising management oversight of functional groups and situations where specific work, previously completed within Union, is now done by an affiliate;

2. the provision of resources and products by affiliates to Union, which are used by Union for its own business purposes; and

3. flow through costs, referring to Union reimbursing affiliates for costs incurred on Union’s behalf but paid directly by the affiliate to a third party.

Union stated that in 2004, it would be acquiring services from three affiliates:

1. Duke Energy Corporation - Duke Corporate Centre (“DCC”), which is the corporate centre for all Duke business units, providing corporate governance, management oversight, business services and resources to Union and incurring flow through costs on behalf of Union;

2. Duke Energy Gas Transmission Corporation (“DEGT”), which is responsible for Duke’s Canadian and American gas distribution, storage and transmission systems, and also provides management oversight and business services to Union; and

3. Westcoast Energy Inc., doing business as Duke Energy Gas Transmission (“DCAN”), which is the corporate centre for Duke’s Canadian companies, providing management oversight, business services, and resources to Union, and incurring flow through costs on behalf of Union.

Union’s Position

Union asserted that the shared service transactions described in the evidence are compliant with the ARC. Union stated that since the issuance of the ARC in 1999, the Board had made three relevant decisions, two relating to EGDI, namely the RP-2001-0032 Decision With Reasons and the RP-2002-0133 Decision and Order, and one relating to Union, the RP-2002-0130 Decision With Reasons.

Union stated that in these three decisions, the Board had set out its criteria for the approval of costs for affiliate transactions, and that Union’s evidence was consistent with these criteria. Union took the position that it had provided clear and detailed disclosure of its business relationships with its affiliates, including a description of the reporting structures, a description of the shared services activities giving rise to the affiliate transactions, information respecting service costing and pricing, and ratepayer benefits.

Union also stated that its evidence had demonstrated that its structuring of affiliate transactions was responsive to the key concerns outlined in these decisions for four reasons. Specifically, Union suggested that the shared services have been undertaken in compliance with the ARC, and that they have created cost efficiencies and economies of scale resulting in a direct ratepayer benefit, without compromising Union’s ability to provide safe, secure and reliable delivery of gas in the Province of Ontario. Union also asserted that the shared services arrangements have not altered the control that Union's management has, and continues to exercise, over the assets and operations of the utility.

Union argued that by providing the outbound services, it is able to maximize the use of existing staff with little or no requirement to increase staffing levels to meet the service requirements of the requesting affiliates. Union also stated that through the use of cost-based pricing for the outbound services, it is able to recover appropriate direct and indirect costs associated with the provision of these services to its affiliates, costs which otherwise would have to be exclusively borne by the ratepayers.

Union also argued that the common benefits of the inbound services included allowing Union to continue to perform portions of shared services activities, allowing for the retention of the in-house knowledge base that it had developed, while enabling it to gain access to the expertise that has been developed in other Duke business units. In Union's view, the Duke model provides the ability to integrate activities and avoid duplication of effort within separate business units, which can optimize the utilization of staff and assets, while sharing fixed costs across more business units, thus producing a lower overall cost.

Union's evidence was to the effect that $10.1 million in ratepayer benefits are realized by the reduction in costs that Union achieves by operating under the Duke shared services business model. These benefits consist of a forecast 2004 charge for services to affiliates of $3.0 million, of which $2.3 million is a direct benefit to the ratepayer. This is because most of Union's direct and indirect costs could not be reduced in the absence of these arrangements.

In addition there is a cost reduction to Union of approximately $7.8 million from inbound shared services, arising from its participation in the Duke model. This is to be compared to the costs which, in Union's view, would have been incurred in completing the activities on a stand-alone basis. This saving was calculated by subtracting the 2004 total charge to Union of $28.7 million for inbound services from an estimated 2004 avoided cost of $36.4 million.

Union further stated that the increase in inbound shared services costs of approximately $26 million, incurred as a result of the move from the WEI model to the Duke model, was more than offset by the decrease in activities performed within Union.

Both the outbound shared services provided by Union to affiliates and the inbound shared services provided to Union by affiliates are supported by service level agreements between Union and its affiliates. General descriptions of the inbound services are incorporated into the individual service schedules while descriptions of outbound shared services form part of the overall agreement.

Union stated that it used its standard Master Services Agreement ("MSA") and supporting service schedules to define the contractual relationship between the service provider and service receiver. Union further stated that the MSA is the same agreement that Union uses with its non-affiliated third party contractors and service providers. Union incorporated a draft of its MSA and generic service schedules for the outbound and inbound shared services into its evidence, as well as drafts of the specific services agreements between Union and its affiliates, which were being executed at the time of filing.

Position of the Parties

Intervenors raised many concerns about the Duke shared services model. Their focus was on the services received by Union from its affiliates. The primary concerns were that:

(a) the costs were not incurred in accordance with the transfer pricing rules in the ARC;

(b) many of the services were available in the marketplace but Union had not gone to the market to establish a market price, as required by the ARC, and this was because Duke's shared services model was imposed on Union;

(c) there was insufficient evidence to demonstrate the reasonableness of the costs incurred by Union as a result of its participation in the Duke shared services model; and

(d) some of the arrangements that Union has with its affiliates are primarily to enhance the competitiveness of the affiliates.

Board Findings

Union stated that the purpose of its affiliate relations evidence was threefold:

1. to describe the shared services transactions between Union and its affiliates and the costs to be included in the determination of Union’s 2004 cost of service;

2. to demonstrate that Union’s shared services transactions are compliant with the Board’s ARC; and

3. to demonstrate that Union’s shared services transactions result in reasonably incurred costs of providing utility services producing net benefits for ratepayers.

The Board must determine whether the affiliate transactions, as described in the evidence, are in compliance with the ARC and whether the costs are reasonable and prudently incurred. The ARC’s principle objective is "... to enhance a competitive market while saving ratepayers harmless from the actions of gas distributors, transmitters and storage companies with respect to dealings with their affiliates.” The ARC also indicates that the standards established in the ARC are intended to, amongst other objectives, "minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities".

Section 2.3 of the ARC deals with Transfer Pricing. The relevant sections are restated below:

> 2.3.1 Where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value of the service, resource or product.
>
> 2.3.2 In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the fair market value. For the purpose of purchasing a service, resource or product a valid tendering process shall be evidence of fair market value.
>
> 2.3.3 Where a fair market value is not available for any product, resource or service, a utility shall charge no less than a cost- based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of the utility's approved rate of return or the bank prime rate.

Union seeks to recover in rates $28.7 million attributable to the shared services arrangements existing between Union and its parent and other affiliated companies. Prior to its acquisition by Duke Energy in 2001, Union had engaged in a more modest exchange of services with its then parent Westcoast and other affiliated entities. The cost of those services to Union in 2001 was $2.8 million. The evidence in this case described a very significant increase in such affiliate transactions following the Duke acquisition, representing almost a ten fold increase in value over the intervening two years.

It is clear from the evidence that the comprehensive shared services arrangements now existing between Union and its affiliates have been undertaken pursuant to a corporate strategy originating with the parent which is designed to maximize benefit to the family of companies, and not necessarily to maximize benefit to Union. Union was not given a choice -- it was required to participate in the Duke shared services model. It had no choice about any material aspect of the shared services model. It was clear that Union was expected to receive and provide services as part of the team of companies falling under the Duke umbrella. This system of shared services is designed for the benefit of the parent, and the affiliates are servants to that objective. While that is a respectable and understandable objective of the parent, the Board's objective is to ensure that Union's ratepayers, at a minimum, are not harmed by these arrangements. The success or failure of the parent's corporate purpose is tangential, at best.

Therefore, if the Board is to approve the expenditures associated with the shared services arrangements, the Board must be satisfied that such expenditures can be definitively quantified, are at a reasonable cost, have been incurred prudently, and meet the governing regulatory requirements.

In considering Union's claim, the Board is faced with serious evidentiary deficiencies which make it impossible for it to allow Union to recover in rates the full amount that it seeks.

First, the Board does not have before it a sufficiently detailed schedule of services and costs of services which make up the shared services scheme. It is impossible to make any finding respecting the scope and accuracy of the services and costs respectively in the absence of a breakdown of how the costs for services are arrived at and accounted for. In order to be able to find that the shared services costs are reasonable, the Board would require a detailed description of services for which recovery is sought, and a consistent, coherent, and reasonable approach to the methodology used to arrive at the costs claimed.

A significant number of what were previously core utility functions were outsourced by Union prior to the acquisition of Westcoast Energy Inc. by Duke Energy Corporation in March, 2002. These included Environment, Health and Safety, Finance, Human Resources, Information Technology, Insurance Services, Internal Audit, Investor Relations, Legal, Public Affairs, Strategic Planning, Taxation, Treasury, and Trustee. Since the acquisition by Duke, Corporate Services, Engineering and Procurement, Storage and Transportation Marketing, and Underground Storage Engineering have been added to the list. The total cost for all services to be provided by affiliates in fiscal 2004, according to Union's evidence will be $28.7 million. At the same time Union is providing outbound shared services to nine affiliate companies using staff and assets primarily required to support the regulated utility.

The Board is concerned that a non-regulated parent company, Duke Energy Inc., has imposed a master services agreement upon Union, which in turn seeks to recover the ensuing costs from its ratepayers. The Board notes the significance of some of the increases in these costs: Environment, Health and Safety increased from a 2002 figure of $244,000 to $470,000 for 2004. Finance increased from $143,000 to $643,000. Human Resources increased from $224,000 in 2002 to $2,523,000 in 2004. Public Affairs increased from $102,000 to $419,000.

The cost of the inbound services are tangible and real. The benefits have not been demonstrated. At best they are an estimate of the additional costs that Union claims it might have incurred, had the service not been outsourced. Union claims that no competitive market exists for many of these services and relies upon the Board’s ARC, particularly paragraph 2.3.3 to justify the service agreement costs it proposes to recover for 2004.

The second difficulty confronting the Board in this matter, is that there is insufficient evidence that the acquisition of these shared services by Union was undertaken prudently, that is, in Union’s interest, as opposed to being undertaken as part of a broader corporate strategy of Duke. Indeed, the evidence that is before the Board is that the shared services arrangement was not optional, and that its purpose was to serve a broad corporate objective, not Union's responsibility as a regulated utility in Ontario.

The final difficulty confronting the Board is that it is unable to conclude on the basis of the evidence that the shared services arrangement meets the requirements of the ARC, to which the Applicant is subject. Depending upon the nature of the service received from an affiliate, the ARC requires Union to demonstrate that the services provided by its affiliates are provided at a cost not greater than the fair market value of the service or, where no fair market value can be determined, that the services are provided at the affiliate’s cost, including a rate of return component. The Board was provided no evidence that would enable it to make these determinations. None of the affiliates, through Union, has made available costing information, and there is no evidence establishing that a bona fide tendering process was conducted with respect to any of the services provided pursuant to the arrangement. Union has not demonstrated that its affiliate transactions are in compliance with the ARC.

The requirements of the ARC cannot be met through the avoided cost methodology put forward by Union. The kind of information needed is set out in Sections 2.3.2 and 2.3.3 of the ARC. It is only with this type of information in hand that the Board can properly determine whether the charges which Union is being assessed for the outsourced services are reasonable.

The Board does not have evidence before it that the costs charged to Union by its affiliates under the service agreements are cost based. Neither is the Board convinced that all of the services in question could not have been provided by Union at the same or lower cost. The Board is particularly perplexed that Union found it necessary to outsource storage and transportation marketing, and underground storage engineering, functions in which Union has been highly successful in developing the ex-franchise market. One could reasonably assume that these services could be provided by Union, given its knowledge and expertise, at the same or lower costs.

For all of the preceding reasons, the Board is not convinced that there is a ratepayer benefit of $10.1 million resulting from affiliate transactions, as stated by Union. While the Board finds that there is a ratepayer benefit of $2.8 million associated with the outbound services, the Board finds that the net benefit of $7.3 million claimed by Union from the inbound services has not been established.

However, the Board also believes that the Utility and its ratepayers receive some benefit from the shared services arrangements, and therefore, some portion of the Applicant's claim should be recognized. The Board's difficulty is in finding an appropriate rationale for that recognition, and a quantification methodology, given the evidentiary deficiencies discussed above.

In EBRO 499, the Board approved the recovery of $2.8 million for the inbound services identified at that time. While the Board expects that Union would have achieved efficiencies during the term of its PBR plan in 2001, 2002 and 2003, we believe that applying the inflation factor for each of those years to that original shared service cost over the three years of the PBR period, will produce a reasonable proxy for the 2004 cost of those services. The Board will allow for the continued recovery of these costs, appropriately adjusted for inflation, with the removal of any double counting of costs that may also be included in the cost recovery permitted in subsequent paragraphs.

$10.7 million of the costs that Union seeks to recover are flow-through costs related to services provided by third parties to the Duke family of companies, including Union. CAC takes the position that these costs should not be recoverable. However, the Board is of the view that to the extent that such costs can be demonstrated to represent a pass-through of third party costs and to be in compliance with Sections 2.3.2 and 2.3.3 of the ARC, such costs would be recoverable from Union's customers. Accordingly, the Board will allow the recovery of these costs in 2004 rates. However, recovery of similar costs in future proceedings may be denied if the Company is unable to provide evidence satisfactory to the Board that these charges are in compliance with the relevant sections of the ARC.

The Board will not allow the recovery of the remainder of Union's affiliate transactions costs in 2004 rates. In subsequent proceedings, Union will have to provide evidence satisfactory to the Board demonstrating that such costs are incurred in compliance with the relevant sections of the ARC, as outlined above, in order to recover those costs in rates.

The cost of outsourced core utility functions must be incurred in conformity with the ARC before they can be recovered in rates. The avoided cost methodology employed by Union in this proceeding does not achieve this objective.

The Board has determined that a portion of the affiliate transaction costs are recoverable in rates, subject to any double counting that may occur in the two amounts that the Board has identified. In preparing the draft rate order, the Board directs Union to remove any costs that are double counted. Union shall provide a report on the specific costs included in rates, at the time it files the draft rate order.

The Board is also concerned that the MSA and service schedules are lacking in appropriate detail and may not be in compliance with Section 2.2.1 of the ARC, which outlines what should be included in such a service agreement. Union filed only a draft version of the MSA in this proceeding. The Board requires Union to provide a final signed version of the MSA that is compliant with the relevant provisions of the ARC.

Some intervenors argued that Union should be directed to obtain an independent audit review of the corporate cost allocation methodology that underpins the Duke shared services model. While the Board is only allowing Union to recover a portion of the cost of the shared services, the Board is of the view that an independent audit review may be one means that could be considered by Union as a vehicle for addressing some of the Board's concerns.

The Board reiterates the opinion of the panel in the EGDI 2002 rates decision (Decision With Reasons, dated December 13, 2002, RP-2001-0032), that in reviewing transfer pricing, the basic regulatory principle is that all rates charged by a regulated utility must be just and reasonable. Therefore only just and reasonable costs can be included in the utility's revenue requirement. Without competitive tendering of the services, the onus remains on Union to establish that the costs incurred are just and reasonable.

CEED has raised a concern about the interaction between the Utility and its affiliates who deal in the sale of ex-franchise gas, storage and transportation. The evidence was clear that when Union identifies gas supply or storage that is surplus to its in-franchise system requirements, it uses DEGT, an affiliate, as its agent to market those assets on its behalf, on the open market. The concern expressed by CEED relates to the competitive advantage that this arrangement might give to DEGT over other, non-affiliated competitors in the same market. In its response to an Undertaking, Union provided an example of how it communicates information about available capacity to DEGT. In its reply argument, Union stated that the service agreement requires DEGT to keep confidential "any customer information released to or obtained by DEGT." The record is not clear on whether Union is providing information to DEGT in conformity with the requirements of section 2.6 of the ARC.

CEED has also raised a concern about the information that Union is providing to MHP. In its reply argument, Union has provided a high level description of the information it is providing to MHP.

The Board requires Union to file a report within 60 days of this decision describing in detail the nature of the information it provides to DEGT and MHP, and what steps it takes to ensure compliance with section 2.6 of the ARC.

2.4 GDAR AND ABC

Union's Request

The Board issued its Gas Distribution Access Rule ("GDAR" or the "Rule") on December 11, 2002, following an extensive public consultation process. Union is incurring O&M costs and capital costs associated with compliance with the GDAR. Union seeks to recover in rates $4.78 million in capital and $1.3 million of O&M costs, $540,000 of which represents the startup cost and $760,000 represents the annual operating cost. Union also wants to establish a deferral account to track the costs incurred to modify the billing system to comply with the GDAR. Finally, Union wants Board approval to continue its Agency, Billing and Collection ("ABC") service, without further time limit.

Union's Position

In its prefiled evidence, Union stated that while it was largely compliant with most aspects of the Rule, compliance with Chapter 3, Gas Distributor - Gas Vendor Relations, and Chapter 4, Service Transaction Requests ("STR"), could not be accomplished without the expenditure of significant additional funds.

Union argued that since GDAR implementation is driven solely by regulatory compliance requirements, it was not necessary for Union to demonstrate that the benefits of implementation outweigh the costs to recover its GDAR expenditures.

Union stated that compliance with Chapter 4 would require system and process changes, and that Union had decided to adopt a phased approach to achieve compliance. The key phases are Project Planning, Scope and Analysis, Design, Test, Build, and Implementation. Union planned to retain the same consultant that had worked on the system changes required to accommodate unbundling, to develop enhancements to its Unionline system to comply with Chapter 4 requirements. The Unionline system, an online customer transaction system, is currently used to manage Direct Purchase transactions, including service transaction requests.

With respect to Chapter 4 compliance, Union stated that implementation would result in significant changes to Union's current STR process. Such changes would increase the number of stages of processing, increase the use of additional data elements, and require the date stamping of STRs, all of which would increase complexity and cost. These changes would also increase initial STR rejections and suspensions. Union would have to adapt its systems and processes to accommodate these changes, while meeting the GDAR imposed time limits for the multiple stages of the STR process.

Chapter 4 compliance would require Union to process customer-initiated requests to return to sales service. At present, such requests are made by the customer to the gas vendor, and may result in the vendor requesting that the customer return to sales service. To add this functionality to its system, Union submitted there would be an increase in Union's staffing requirements to manually input customer-initiated STRs to the Unionline system, as the customers would not have access to Unionline.

Union added that "[i]n light of Union's experience with recovering the costs of offering an unbundled storage service, Union is not prepared to expend significant funds without certainty with respect to the recovery of the costs associated with GDAR compliance." As such, Union stated that it would only commit to the expenditure of $200,000 on the project's Scope and Analysis phase prior to a Board determination on the recovery of all GDAR costs.

Union requested exemption from Article 4.3.3.1(a) of the Rule contending that compliance would require Union to incur significant costs with little or no customer benefits. Union also requested Board clarification of Articles 4.3.7.4 and 4.3.9.1 of the Rule.

Union also requested Board approval to continue its Agency, Billing and Collection ("ABC") service, without a further time limit. ABC service is offered to marketers to enable them to bill customers through Union. Union charges marketers an ABC service fee that includes a provision for bad debt. Since ABC service is a non-utility function, Union stated that it required Board approval pursuant to its Undertakings to the Lieutenant Governor in Council. Union proposed to change the ABC Service by adding to it the collection of fees or penalties that a consumer may owe to a retailer under the contract between the Retailer and the customer. Under Union's proposal such fees and penalties would form an integral part of Union's ABC service.

Union currently bills approximately 535,000 direct purchase customers on behalf of 10 gas marketers.

Position of the Parties

Several intervenors argued that the one time O&M costs should be amortized over a number of years, instead of being collected in 2004 rates, on the basis that the benefits from this expenditure will accrue over more than one year.

VECC, CAC, LPMA supported the creation of a deferral account to track the costs associated with modifying the billing system. They submitted that the Board should review the prudence of the expenditures. Some parties viewed the O&M and capital costs as excessive and also opposed the creation of a deferral account.

Several parties expressed concern that Union was proposing to collect penalties or exit fees on behalf of marketers, as part of its ABC service. Concern was also expressed about the bad debt component of Union's case and that Union may be taking on risk associated with commodity charges payable to marketers. Schools argued that the ABC service fee should include appropriate compensation to the utility to ensure that ratepayers are not subsidizing marketers

Board Findings

(a) GDAR costs

The Board does not find the revised O&M costs and the capital costs required to comply with GDAR in 2004 to be unreasonable. However, the Board finds that the $540,000 one-time component of the O&M costs should be amortized and expensed over three years, on the basis that benefits will accrue from this expenditure past 2004. Amortization will provide a better match between the cost and the benefits derived from the expenditure. Therefore the amount to be recovered in fiscal 2004 for the one time O&M costs shall be reduced from $540,000 to $180,000

(b) The GDAR deferral account

The Board acknowledges that the nature of the expense is non-recurring, material, and the program arises as the result of a regulatory directive, and therefore meets the criteria for setting up a deferral account.

The Board approves the creation of the deferral account to track costs to modify the billing system to comply with Chapter 4 requirement of the GDAR. However, these are costs that will be incurred by the third party owner of the billing system and will be carefully reviewed for prudent actions by the Applicant.

(c) ABC Service

The issue surrounding the extension of ABC service to include collection of exit fees is problematic.

First, the Board does not accept Union’s argument that the Board has no jurisdiction over the terms of its ABC service.

The Board's jurisdiction flows from two provisions of the Act. Section 36 (1), which is part of the section that sets out the Board's ratemaking powers, states:

> No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

Section 36 (4) states:

> An order under this section may include conditions, classifications or practices applicable to the sale, transmission, distribution or storage of gas, including rules respecting the calculation of rates.

Section 131 states:

> Despite the repeal of the Ontario Energy Board Act under the Energy Competition Act, 1998, any undertaking made to the Lieutenant Governor in Council under the repealed Act, if valid immediately before this section comes into force, continues to be valid and binding.

The current undertaking provides, in part, as follows:

> 2.1 Union shall not, except through an affiliate or affiliates, carry on any business activity, other than the transmission, distribution or storage of gas, without the prior approval of the Board.

The Board has been established by the Provincial Legislature to provide economic regulation of the distribution of natural gas within Ontario. In establishing just and reasonable rates, the Board must take into account and regulate a broad range of utility activities which impact on utility costs. It is important to note that the ABC Service represents a key aspect of the Utility's relationship to marketers and the relationship between marketers and their customers. Given the provisions of the Act and the undertaking that Union entered into with the Lieutenant Governor General in Council, the Board is of the view that it has jurisdiction to address the components of the ABC service. It is not logical that the Board, on the one hand, can decide whether to approve the continuation of the ABC service but, on the other hand, cannot examine the components of the ABC service as part of that approval process.

Union has also requested Board approval for continuation of its ABC service and gas supply "... without any limitation on the term of the approval." The Board is of the view that it is not appropriate to provide approval indefinitely for a regulated service. Union must expect to report to the Board on the costs and benefits of all of its Board approved activities. Therefore, the Board approves the continuation of Union's ABC service for a further period of five years, 2004 through 2008, subject to there being no intervening circumstances sufficient, in the Board's view, to necessitate a reconsideration. Prior to the end of that period, Union is directed to file a report with the Board addressing the status of its current ABC service.

The Board is not convinced that Union should be recovering exit fees on behalf of marketers. The fact that the Board has approved such fees for the early termination of a contract under the GDAR rule does not require that such fees be recovered by Union. It appears to the Board that such fees should be a matter between the marketer and the customer. Also, the Board notes that Union is not necessarily a disinterested party, since some customers subject to the exit fees may be returning to system gas. The Board sees no compelling reason why Union should act as the billing agent for all marketer commodity related customer charges.

The Board also notes the concerns of parties with respect to the additional bad debt that Union may incur. The Board directs that Union shall not recover exit fees or penalties on behalf of marketers. Such fees, if and when they are incurred, should be recovered by the marketers themselves.

2.5 LINES OF BUSINESS

Union's Request

Union is requesting that the Board remove the requirement upon it to file financial information on a lines of business basis.

Background

In its RP-1999-0017 Decision, the Board directed Union to file with it financial information segregated by lines of business. The Board justified this requirement on the basis that as it had introduced a new regulatory framework, it was necessary to define the related filing requirements. In so doing, the Board stated that it needed to balance the value of the information requested against the costs of providing it. The Board accepted, as a starting point, Union's undertaking to provide certain information to the customer review process.. However, the Board also stated its belief that the filing of financial information segregated by lines of business was required in order to properly administer the PBR plan.

Union's Position

Union complied with the Board's directive, submitting the required financial information in the current proceeding. However, in its submissions, Union questioned the costs and benefits of compliance with this directive, and asked the Board to remove it.

Union argued that the sale of commodity is not a separate business because commodity sales are only offered bundled with distribution service; further, Union is not allowed to make a profit on commodity sales. Union submitted that, rather than being a separate line of business, Union's commodity sales simply reflected the fact that Union had to meet the supply needs of customers who had chosen not to be served by a gas vendor.

Union added that it had no intention of moving its regulated storage and transmission facilities into a separate company. Union argued that it would not separate its operations into lines of business as there was no advantage to the business or to ratepayers in doing so. Union stated that while there was a significant expense in complying with the directive, it was not clear how the information so produced could be meaningfully used. Union noted that no intervenors opposed Union's proposal and that Board approval of the proposal would lower Union's 2004 O&M costs by $325,000.

Board Findings

The Board notes Union's assertion that it has no intention of separating any part of its
operations. The Board further notes that no parties opposed Union's request. Given that there is no evidence that the benefits of retaining the directive equal or exceed the costs of compliance, and given that Union has filed a comprehensive cost allocation study in this proceeding, the Board approves Union's request to remove the requirement to file financial information on a lines of business basis.

3. GAS SUPPLY ISSUES

3.1 GAS COSTS AND EXPENSES - GAS SUPPLY PLAN

Background

Gas Supply Plan

Union contracts for upstream transportation capacity on behalf of its sales service customers and these transportation contracts, along with storage assets, are then managed by Union to provide an integrated service to all sales service and bundled direct purchase customers.

Union's Gas Supply Plan (the "Plan") is a tool used to model and optimize use of these gas supply assets and is developed using the SENDOUT optimization software which it has used for a number of years. The updated 2004 Plan was prepared in the summer of 2003.

The Plan is used to generate a forecast of natural gas supplies and services required by Union's in-franchise sales service and bundled direct purchase customers. It provides a long-term planning tool covering a five-year forecast period from 2003 to 2007.

Union's Position

Union stated that the Plan reflects its supply portfolio, which is designed to ensure secure supply and reliable service, minimize risk by diversifying term, supply basins and upstream pipelines, meet anticipated peak-day and seasonal gas delivery requirements, and deliver gas to various receipt points on Union's system to maintain system integrity. The plan is also designed to optimize the transportation assets in both the Northern and Eastern Operations area ("North") and the Southern Operations area ("South"). To minimize potential stranded costs, Union diverts TransCanada PipeLines ("TCPL") capacity that is required to serve the North peak day requirements to the South. The Plan is also used to facilitate the refill of storage inventory prior to entering the winter season.

Union has provided its 2003 to 2007 In-Franchise Supply/Demand forecast for sales service and bundled direct purchase customers.

Union stated that a key objective of the Plan is to optimize system-wide load factors. This is accomplished by managing upstream transportation capacity on an integrated basis and shifting the use of this capacity from one area to serve demand in another area when the opportunity and the need arise. In the North, the transportation capacity necessary to meet peak day demands on a firm basis exceeds that required to meet the annual demand requirements. Unutilized Northern firm transportation ("FT") capacity is forecast for the 2004 test year resulting in Unabsorbed Demand Charges ("UDC") in the North, which are recovered from Northern customers. No UDC is forecast for the South.

Union had modified its supply plan for the Western Delivery Area ("WDA") and the Northern Delivery Area ("NDA") to optimize capacity as described above. Specifically, the contractual amounts were decreased by 20,000 GJ/day and 40,000 GJ/day respectively, with corresponding increases in the TCPL STS daily withdrawal quantities in the two delivery areas. Because these long-term FT and storage transportation service ("STS") contracts have now completed their primary terms of 10 to 15 years, they will be renewed on a one-year rolling basis. Union stated that the net result of these changes is a more efficient system and reduced exposure to UDC in the North.

Union noted that a key element in achieving portfolio flexibility is the planned use of spot gas purchases. However, it took the position that in the current market, the cost to ratepayers of incurring UDC as a result of warmer than normal weather is significantly lower than the cost of procuring winter spot gas for delivery to Dawn.

There is no evidence suggesting that current market conditions will change in the near future. Accordingly, Union has considered rebalancing its portfolio in favour of holding more firm upstream transportation capacity with less dependence on winter spot gas as a means of reducing the exposure to winter spot gas pricing volatility.

In an addendum to its evidence, Union stated that it had prepared its original Gas Supply evidence anticipating that its response to the Board's load balancing directive (see Chapter 8.1) would be implemented and fully functional in the winter of 2003/04. However, Union's revised expectation was that the new load balancing contract process would not be fully functional until November 1, 2004. Therefore, Union stated that it might be required to purchase incremental spot gas for the bundled direct purchase customers in the South for the winter of 2003/04. Union proposed that any spot volumes purchased at or below what is already in the Plan would be allocated to all sales service customers and North Bundled T-service customers, with any spot volumes purchased in excess of the planned volumes to be allocated to any rate class (both North and South) that had a March 31, 2004 consumption imbalance.

Union also noted other key assumptions made in determining the Plan, as follows:

1. winter peaking service ("WPS") was forecast to be required in both operating areas;

2. pricing assumptions were prepared in the summer of 2003, using May 2003 consensus forecast pricing and tolls in effect at the time;

3. all bundled direct purchase Daily Contract Quantities ("DCQ") were included assuming that the proportion of direct purchase customers remained constant as of April 1, 2002;

4. the Plan is predicated on the 20 year declining weather trend forecast outlined elsewhere in the evidence; and

5. 2003 to 2007 Peak Storage Availability and Utilization forecast is assumed, again as outlined elsewhere in the evidence.

Union uses winter-peaking services as an alternative to adding capacity on the Dawn-Trafalgar transmission system. Its rationale is that large capital outlays for transmission expansion should be delayed until there is significant shortfall in the Dawn-Trafalgar system. There is a forecast capacity shortfall for the 2003-2004 and 2004-2005 winters resulting from this deferral of Dawn-Trafalgar expansion. Union proposed to meet this shortfall by the most economic means available, through the purchase of a winter-peaking service, the cost of which is $2.7 million.

Union has used a 20 year trend weather-normalization methodology for the past two years for operational purposes. This includes such elements as the amount of upstream transmission that it acquires and the amount of storage needed to meet in-franchise demand. Union's position was that the use of the 20-year trend enhances operational efficiency and maximizes asset utilization, while avoiding unnecessary costs arising from over-forecasting items such as UDC. Union stated that using the 20-year trend benefits both direct purchase and sales service customers because the annual DCQs, pipe allocations, and UDC exposure of direct purchase customers would increase under the 30-year average methodology.

Union took the position that the gas supply issues in this proceeding were quite straightforward and stated that no intervenor had opposed its evidence in this area.

Positions of the Parties

Energy Objective expressed concerns with Union's spot purchases of Ontario produced gas, stating that the methodology used involved purchasing gas from Ontario producers on a spot basis using a monthly Niagara index, while Union maintained that the acquisition of Ontario gas production is not a spot purchase, but instead part of Union's planned purchases. In this context, Energy Objective objected to the fact that Union deducts a $0.24 per gigajoule charge from the gas producer for transportation and balancing. Energy Objective stated that both its evidence and that of Union support the view that Ontario gas production is consumed by local markets and helps to balance those markets. Therefore, Energy

Objective concluded that the application of a charge for transportation and balancing is inappropriate. Energy Objective requested that the Board require Union to purchase Ontario gas production using a Dawn or Niagara monthly index without any deductions.

Energy Objective criticized Union's policy of a Parkway delivery commitment for Ontario gas producers wishing to market directly to Union's in-franchise customers. Energy Objective stated that Union provided no evidence that supports this requirement. While recognizing Union's sensitivity about favouring one marketing party over another, Energy Objective stated that removing the Parkway delivery commitment for marketing Ontario natural gas to customers within the Union franchise area does not favour one marketer over another, but provides added value for Ontario natural gas, and encourages the additional development of natural gas reserves within the province. Therefore, Energy Objective submitted that the Board should encourage Union to abandon a Parkway delivery commitment for any Ontario gas producer wishing to market Ontario production gas to an in-franchise Union customer.

VECC stated that Union's evidence implies that any costs associated with UDC in the South will be directly allocated to the South sales service customers, as will any costs associated with spot gas purchased to respond to demand in the South. VECC took the position that such pre-determined allocation is not consistent with principles of cost causality and, as a result, there should not be an automatic pre-determined allocation process, prior to any assessment as to the cause of the costs. Regarding Union's proposal to allocate spot gas solely to sales system customers, VECC stated that it was not evident that Union's proposal for load balancing prevents direct purchase customers from causing a need for spot gas purchases. Therefore, VECC rejected the notion that spot gas costs should never be allocated to direct purchase customers.

CME urged the Board not to approve Union's proposal to use the 20-year weather trend for gas supply planning purposes. CME based this recommendation on its concern that if the weather proved to be colder than the 20-year trend method forecast suggests, Union would not have enough storage capacity to meet the needs of its customers.

LPMA recommended that the Board accept Union's overall gas supply plan as appropriate and reasonable.

Board Findings

Union noted that it was seeking approval to use the 20-year trend methodology for rate-making purposes to underpin Union's revenue forecasts (Chapter 2.2). If it did not receive approval for use of the 20-year trend methodology for rate-making purposes, Union would likely not continue to operate under two methodologies. Union concluded that if the Board did not approve the 20-year trend methodology in this cost of service application, but maintained the 30-year trend, Union was likely to return to the 30-year average for planning purposes and would seek recovery in any future case of all costs associated with that change.

The Board notes that there were relatively few intervenor concerns expressed about Union's Gas Supply Plan.

The concerns raised by CME related to Union's use of the 20-year weather trend for gas supply planning purposes are dealt with in Chapter 2.2 of this Decision.

Regarding the concerns of Energy Objective related to both Union's spot purchases of Ontario gas and the policy of a Parkway delivery commitment for Ontario gas producers, the Board is of the view that Energy Objective has not provided sufficient support for the positions it is advancing. The Board considers the production and marketing of Ontario natural gas to be an important policy issue in the province's energy supply plan. The Board invites Energy Objective to participate in the Natural Gas Forum to have its concerns considered in a broader policy context. Alternatively, the Board would welcome further evidence touching on this subject in subsequent proceedings. In the interim, the Board accepts Union's position on these matters.

The Board notes VECC's concern that spot gas costs are not allocated to direct purchase customers. The Board does not accept the proposition that costs should be allocated to a rate class without regard to cost causality. The Board expects that the load balancing proposal discussed subsequently will have the effect of significantly reducing, if not eliminating, the need for spot gas for balancing direct purchase gas accounts. VECC has not proposed any specific alternatives to Union's proposals. The Board accepts Union's position on this matter.

The Board accepts the principles underlying Union's proposed Gas Supply Plan for 2004. However, Union is directed to revise its Gas Supply Plan for 2004 so that the Plan reflects the Board's findings with regard to the approved weather nomalization methodology for 2004 as prescribed in Chapter 2.2.

3.2 UPSTREAM TRANSPORTATION ALLOCATION METHODOLOGY (VERTICAL SLICE)

Union stated that it currently allocates upstream transportation to Southern region customers migrating from sales service to direct purchase using the vertical slice allocation methodology approved by the Board in RP-1999-0017. The vertical slice is determined based on Union's projected upstream transportation portfolio to serve Southern sales customers commencing each November 1st and remaining in effect for one year. The portfolio is restructured each successive November 1st. Union proposed to continue with the vertical slice, using its projected upstream transportation portfolio as of November 1, 2003.

Union described, in its August 2003 update, the two new transportation components to be included in this portfolio beginning November 1, 2003.

The first such new contract is a firm transportation contract with Trunkline Gas Company from the Gulf Coast of Mexico to Bourbon, and Panhandle Eastern Pipeline from Bourbon to Ojibway. This contract is effective November 1, 2003 and has a principal term of two years with a firm capacity of 60,138 GJ/day during the first year and 42,202 GJ/day during the second year. The volumes are obligated at Parkway, which is facilitated by a firm Ojibway to Parkway service. The contract also contains a provision such that the volume for the second year can be reduced by up to 5,275 GJ/day.

The second contract is for firm transportation on Vector Pipelines, transporting gas from Chicago to Dawn. Union stated that there should be no controversy associated with its use of Vector, as Vector is no longer an affiliate of Union. This contract is also effective November 1, 2003 and has a principal term of five years and a firm capacity of 84,405 GJ/day which is obligated at Dawn. Similar to the Trunkline contract, this contract contains a provision allowing Union to reduce the total volume of the contract by up to 5,275 GJ/day annually.

Union stated that the above-referenced volume reduction provisions were incorporated into these two contracts in order to allow for a non-renewal option for direct purchase customers that receive a volume of capacity as a component of their vertical slice when they migrate from sales service to direct purchase. In the case of the Trunkline contract, such customers' subsequent obligated replacement would be to provide their own delivered service arrangements at Parkway, while in the case of the Vector contract, the equivalent obligation would be at Dawn.

Union stated that the additional benefits of both of these contracts are that new supply lands at a cost which is competitive with the major alternative, TCPL, while also providing an overall improvement in the diversity and flexibility of the portfolio for system sales service and direct purchase customers.

Union took the position that no intervenor had opposed its proposed transportation portfolio and that it should therefore be accepted by the Board.

Positions of the Parties

IGUA stated that initially it had been concerned about Union's acquisition of incremental upstream transportation capacity from Vector. It was concerned that the full toll Alliance/Vector transportation route to receipt points on the Union system was more costly than the full toll upstream transportation route on TCPL. However, IGUA concluded that Union's evidence with respect to these matters had alleviated its concerns.

CAC supported the continued use of the vertical slice methodology.

Board Findings

The Board notes that few intervenors addressed the proposed upstream transportation allocation. The Board accepts Union's submission that the two new transportation contracts on the Vector line will result in overall improvement in the diversity and flexibility of the portfolio for system sales service and direct purchase customers. The Board therefore accepts Union's proposed upstream transportation allocation for the Vertical Slice.

4. OPERATING REVENUE

4.1 2004 GENERAL SERVICE FORECAST DEMAND

Union's Request

Union is seeking the Board's approval of its general service demand forecast for 2004.

Background

Union's general service demand forecast applies to M2 (residential, commercial, and industrial), R01 (residential and commercial), and R10 (commercial and industrial) customers. Overall, the general service market comprises 35% of total in-franchise throughput, including gas procured by direct purchasers who use Union's transportation service. The remaining 65% is mainly comprised of throughput relating to contract class customers.

Union uses a regional market assessment of new housing and construction activities to forecast new customer attachments by month to arrive at an estimate of the number of forecasted customers. Union then forecasts a monthly normalized average consumption ("NAC") for residential, commercial, and industrial customers in the general service rate classes. Union then adjusts its NAC forecast for normal weather using the 20-year trend methodology it has proposed.

The NAC estimates are then further adjusted for marketing effects and Union's Demand Supply Management ("DSM") activities. In its pre-filed evidence, Union quantified the impacts on its NAC estimates of weather, non-DSM energy efficiency improvements, and retail natural gas prices.

The NAC estimates for the first year of the forecast (2002) are compared to an outlook for the same year. If the NAC estimates are within one standard deviation of the outlook, the estimates are said to pass the reasonableness test. If not, the forecast is adjusted to be at one standard deviation from the outlook.

In this proceeding, the 2002 NAC forecast was within one standard deviation of the outlook for all but the industrial customers. Accordingly, the industrial NAC forecast was increased to be one standard deviation below the outlook, and this adjustment was carried forward to the 2004 NAC forecast.

The NAC forecast is multiplied by the forecast number of customers by class, by month to arrive at the volume forecast for general service customers. Union’s updated 2004 general service demand forecast is 5,193.1 10^6m^3.

Position of the Parties

Intervenors expressed the concern that Union’s NAC forecast was subjective and its methodological and statistical validity questionable.

Union’s Position

Union stated that the anticipated downward NAC trend was reflective of the same general warming trend as was incorporated into its proposed weather normalization methodology and that the methodological approaches that it had employed were sound, with its witnesses having provided valid reasons for their use.

Board Findings

The Board has concerns with respect to the subjectivity of Union’s NAC methodology, for example, the decisions as to which equations to add and which to omit, when the results of significance tests appear to conflict, to some degree, with

Union's decisions in this regard. Also, applications of Union's reasonableness test seem to be arbitrary, or at least open to question, in those instances where results are changed to be at variance by a maximum of one standard deviation. While the Board appreciates that there is some judgment required in the practice of forecasting, the Board is unable to determine whether Union's NAC methodology results in unbiased forecasts. The Board is further unable to determine, on the basis of the evidence before it, whether Union's NAC methodology produces an estimate of normalized average use that is unbiased with respect to its forecasts of a decline due its weather normalization forecasts.

Notwithstanding the Board's reservations, as a practical matter, the Board will approve Union's current NAC methodology for the 2004 test year in conjunction with the weather normalization methodology approved elsewhere in this Decision. Further, the Board directs Union to undertake a thorough and statistically rigorous review of its NAC methodology and present the results of this study at its next rates case so that all parties will have the opportunity to test Union's proposed methodology.

4.2 2004 CONTRACT CUSTOMER FORECAST DEMAND

Union's Request

Union is seeking the Board's approval of its contract customer demand forecast for 2004.

Background

The contract customer forecasts include the M4, M5A, M6A, M7, M9, M10, T1, T3, Rate 16, Rate 20, Rate 25, and Rate 100 classes.

In 2002, contract customers accounted for 9,712.5 10^6m^3, or approximately 65% of Union's in-franchise distribution throughput of 14,918 10^6m^3;

To forecast 2004 demand, Union surveyed each individual large contract customer regarding the business outlook and efficiency, expansion, and closure plans, and used this information along with historic load data to prepare its forecast.

Union cited a number of significant market drivers of lower demand:

1. the possibility for some customers of fuel switching in response to changes in commodity or upstream transportation prices;

2. a decrease in the number of marketers, decreasing liquidity and increasing credit requirements and gas prices;

3. the current volatility and legislative changes in the Ontario electric power generation market and their impact on gas demand by a large dual fuelled peaker, eleven existing Independent Power Producers ("IPPs"), three new large gas-fired plants, and other embedded gas generators at industrial and commercial facilities; and

4. implementation of energy efficiency programs and forecast DSM volume reductions of 34.0 10^6m^3 over the two-year period 2003-2004.

Union's actual 2002 contract volume was 9,712.5 10^6m^3 with forecast 2003 and 2004 levels of 9,260 10^6m^3 and 9,351 10^6m^3 respectively.

Union noted that it had experienced significant forecasting errors in the 1999 to 2002 time frame and cited four events from this period that contributed to these errors:

1. the delay in return to service of the Bruce and Pickering nuclear units;

2. the delay in the Ontario electricity market opening;

3. the uncertainty with respect to renewing Union's high-priced IPP-contract customers; and

4. the volatility of natural gas prices during this period.

Union noted that 27.61% of its total throughput for the contract market is for electricity production. When asked to explain why ratepayers could have confidence that the significant forecasting errors of the past would not be repeated, Union cited factors that it believed would bring greater stability to the use of throughput for electricity production. Union stated that because its 2004 forecast takes account of the 18-month IMO forecast of 2,040 MW of nuclear plants back on line and the addition of three new gas fired merchant plants, which will displace some existing load, the variability of the contract demand forecast would be "dramatically narrow[ed]." Union's witness also stated that Union expected current high gas prices to persist, further reducing the variability between forecast and actual contract demand.

Union asserted that the only circumstance under which its contract demand forecast would be significantly below actual 2004 demand would be if natural gas prices went down over the contract period.

Position of the Parties

Intervenors expressed the concern that Union's contract class demand forecasts take insufficient account of the input of the contracting party. Therefore, where necessary, dispute resolution through the Board should be available.

Kitchener disputed Union's 2004 T3 volume forecast of 286.7 10^6m^3 and requested that the Board approve Kitchener's T3 forecast of 306.4 10^6m^3 instead. Kitchener argued that although Union acknowledged Kitchener's load to be heat sensitive, Union's T3 forecast was not normalized.

Kitchener also criticized Union's proposed storage space and deliverability allocations, noting that these were critical parameters in order for a public utility, with a substantial heat sensitive load, to meet its winter period and design day requirements. Kitchener, which had been an M9 customer prior to becoming a T3 customer, quoted the Board's EBRO 412 Decision in support of its position that its storage allocation should not be reduced. With respect to deliverability, Kitchener stated that a higher allocation would reduce load balancing costs because less higher priced gas would have to be purchased and delivered to Union on a peak day.

Kitchener urged the Board to not allow Union to impose storage allocations on an unwilling customer and to make an arbitration facility available to resolve disputes, or direct Union to maintain existing storage parameters until the issue is resolved. Kitchener also urged the Board to direct Union to provide a detailed review of its allocation of space and deliverability sufficient to address Kitchener's concerns at Union's next rate hearing.

OPG urged the Board to reject Union's forecast as the methodology consistently underestimates volume and revenue for M7 firm and R25 interruptible services. OPG also stated that Union's rationale for its 2004 forecast ignores many factors that affect gas-fired generation plants. OPG proposed that Union's volume and revenue forecasts be increased by "2/3rds of the percentage by which Union underestimated volume and revenue during the period 1999 to 2001" to restore symmetry to the forecasts.

Union's Position

Union argued that its approach to contract class forecasting was appropriate and not in need of adjustment.

Union stated that it had not weather normalized Kitchener's load because Kitchener manages weather variances under its T3 contract. In addition, Union does not have the required data to weather normalize Kitchener's load. Union cautioned the Board with respect to deviating from "Union's proven method" noting that Kitchener's true heat sensitive component was not in evidence.

Union asserted that the design of the T3 rate ensured that consumption variances had no material impacts on other classes and using Kitchener's forecast would increase Kitchener's rates.

Union submitted that OPG's criticism of the forecast contract demand methodology used by Union ignored Union's evidence with respect to the relationship between the M7 class and T1 semi-bundled service. Union asserted that its evidence showed that M7 customers had advised Union that they intended to switch to T1 semi-unbundled service. Union argued that any variances should be assessed by looking at the sum of both classes, an exercise that would show no significant variance. As Union has now signed T1 contracts with the large customers which caused the historical variances between M7 and T1 customers, Union argued that these historical variances were unlikely to occur in 2004.

Union stated that OPG's position with respect to Rate 25 was tantamount to a request that the Board disregard the IMO's forecast of when nuclear plants would be in service. Further, Union argued that the technical factors that OPG stated Union should have considered in its forecast, were explicitly considered by the IMO in its forecast.

Board Findings

The Board believes that the contract class forecast should incorporate the input of the customers, in the belief that the contract customers possess some relevant information that Union may not have access to. As such, the Board believes that Union should work cooperatively with these individual customers to develop forecasts that both parties can agree on. The Board recognizes that there may be cases in which agreement can not be achieved at this stage; should this be the case, the Board expects the parties to communicate with Board staff, informing staff of the impasse in negotiations and requesting any staff assistance that may bring the parties to agreement. If this second stage should not be successful, the Board expects both parties to inform the Board to seek Board resolution of the dispute. The Board expects that any outstanding differences in this regard will be brought to the Board's attention well in advance of the associated rates proceeding.

With respect to the T3 forecast, the Board urges Kitchener and Union to work together, again in a timely fashion, to resolve such specific issues as normalization of load and asset allocations.

With respect to OPG's concerns, that Union historically had significantly underestimated R25 interruptible and M7 firm volumes and had ignored what OPG considered to be key elements in deriving its forecasts, the Board reiterates its views on these matters as expressed above. Regarding OPG's proposal to adjust Union's R25 interruptible and M7 firm revenue and volume forecasts, the Board finds that it is unable, on the evidence before it, to accept OPG's forecast, notwithstanding the Board's view that the OPG's views may have some merit.

Notwithstanding the Board's reservations, for the 2004 test year the Board accepts Union's contract customer forecast. The Board expects that Union's 2005 contract customer forecast will address the Board's concerns as expressed above.

4.3 S&T REVENUE ISSUES

Union's Request

Union is requesting the Board's approval for both the level of its S&T revenues and its proposals for allocating deferred margins between the shareholder and the customer.

Background

As part of its EBRO 499 Decision, the Board determined that S&T revenues would be deferred and forecast revenue levels would be shared between the ratepayer and the shareholder. In EBRO 499, Union had forecast approximately $5.6 million in S&T revenues for 1999, 90% of which was included in rates, effectively splitting forecasted S&T revenues 90:10 in favour of the ratepayer, with any net revenues above this amount to be shared 75:25 in favour of the ratepayer.

Union estimated S&T revenue for 2004 at $20.8 million which it proposed to share 75:25 in favour of the ratepayer. The corresponding amounts for 2003 and 2002 were $8.8 million and $22.6 million respectively.

In the oral proceeding, Union attributed the significant decrease in 2003 S&T revenue to market changes. Union suggested that some of its major S&T customers may have left the market and that some services such as Authorized Overrun Service, Hub2Hub™ service, and FT makeup service will not be available in the future. Union added that 6 petajoules ("PJs") of storage have been removed from S&T services. 3 of these PJs were assigned to in-franchise T-service customers, and the other 3 PJs to long-term storage contracts unlikely to be renewed.

Union's forecast was based on the following assumptions:

1. EGDI would take an additional 170,000 GJ/d of Dawn-Parkway service beginning November 1, 2004, due to increased Dawn deliveries;

2. TCPL would take an additional 128,200 GJ/d of Dawn-Parkway service beginning November 1, 2003;

3. Gaz Metropolitain Inc. ("Gmi") would recontract 5.9 PJ of storage in 2003 and 2.1 PJ of storage in 2004 at market-based rates; and

4. $880,000 in revenues would be received for 2003 and 2004 under M13 rates from local gas producers to transport volumes to Dawn, a reduction of $51,000 from 2002.

Long Term Peak Storage - 2003 and 2004

Union calculates the market premium for long term peak storage as the difference between the revenue earned at the market bid rate and the M12 cost based rate at the time of the forecast.

Union stated that long term market revenue from the long term peak storage market would increase from the 2002 actual level of $18.7 million to forecast levels of $21.8 million in 2003 and $34.5 million in 2004 respectively. The long term market premium represents $5.2 million of this amount in 2002 and was forecast to represent $8.6 million and $20.6 million, respectively, for 2003 and 2004. Union attributed the increases in revenues and premiums to its expectation "that existing M12 contracts will renew under C1 market based rates as outlined above."

Transactional & Other Services Forecast

There are three components of this forecast. These are transportation and exchange revenues, balancing service block revenues, and other S&T services revenues. Short term services included in the forecast are transportation, peak storage, balancing services, exchanges, Hub2Hub™, name changes and redirections, and Ontario Production services.

Transportation and Exchange Revenues

Union's S&T transportation and exchange revenues for actual 2002 and updated forecast 2003 and 2004 are $12.5 million, $5.8 million and $2.5 million respectively. The corresponding deferred margins are $5.0 million, -$1.2 million and -$0.3 million respectively. The revenue minus costs yields the gross margin, while the gross margin minus the approved forecast yields the deferred margin.

Union stated that with a balanced gas supply portfolio that meets forecast in-franchise and ex-franchise demands, few firm assets are available on a planned basis to support these services. Asset availability is mainly influenced by weather and market variances. The latter variances include the amount of direct purchase switching, T-service switching, in-franchise growth, changes in customer use, market prices, and S&T demand. While actual results depend on actual weather conditions experienced, Union's forecast assumes normal conditions.

Union cited the following reasons for the decline in the S&T market:

1. a reduction in the number of potential counterparties following the Enron failure;

2. the imposition of more onerous credit requirements on remaining counterparties, reducing the number of transactions;

3. a decrease in peak storage value from $1.50/GJ in 2002, to between $0.45/GJ and $0.75/GJ in 2003, due to reduced summer/winter price differentials for gas; and

4. the expectation that high forecast commodity prices will reduce transactional services demand in the industrial and power generation markets.

Balancing Service Block Revenues

Union's balancing service revenues and deferred margins decreased from $37.1 million in 2002 to a forecasted 2003 and 2004 of $13.4 and $7.5 million respectively. The corresponding deferred margins were $12.3 million in 2002, decreasing to forecast 2003 and 2004 levels of $3.7 million and $1.5 million respectively.

Union attributed the decreased margins on this block for 2003 and 2004 to a number of events in 2002, which are unlikely recur in 2004 including:

1. historically high value of storage in 2002;

2. incremental gas loan revenues due to favourable market conditions in 2002;

3. comparatively lower seasonal loan activity in 2003 due to prior warmer than normal weather; and

4. incremental balancing activity in 2002 due to weather variations.

Other S&T Service Revenues

Union's other S&T Services revenue for actual 2002 and updated forecast 2003 and 2004 are $3.8 million, -$0.3 million and $0.9 million respectively. The corresponding deferred margins are $0.3 million, -$2.3 million and -$1.0 million respectively.

Union, in explaining the decline in these revenues, noted that it managed jointly with Encana a Hub2Hub™ service, whereby a customer delivers gas at the Alberta Energy Company price point ("AECO") hub and simultaneously receives gas at Dawn, so the service is a substitute for transportation. Union realized $3.1 million of revenue in 2002, and is forecasting $0.6 million in revenue for both 2003 and 2004. In response to an interrogatory, Union indicated that it agreed to wind down the service over 2003 and 2004 at Encana's request.

Position of the Parties

Intervenors expressed concerns about the appropriateness of Union's approach to embedding forecast S&T margins and long-term storage premiums into rates, including variance account treatment.

Numerous intervenors took the position that Union's proposed sharing ratios should be adjusted to provide a higher proportion for the ratepayer and less for the shareholder, including Kitchener, FONOM, LPMA, CAC, IGUA, CME, Schools and VECC.

Union's Position

Union asked the Board to accept its 2004 forecast of incremental S&T revenues of $20.8 million. Union noted that the Board has approved a 75:25 sharing for S&T transactional revenues since EBRO 499 and the same sharing proportion for the total of S&T revenues and the long-term storage premium since RP-1999-0017.

Union took the position that to embed a greater fraction of the forecast margins into rates would expose Union to an inappropriate level of risk, and not reflect the Board's statements regarding incentive levels. Union submitted that if any percentage of the 2004 deferred margins were put into rates, the S&T and market premium deferral accounts should record positive or negative variations shared 75:25 in favour of the ratepayer.

Union proposed to embed the 1999 forecast of S&T margins in rates with any additional margin shared 75:25. Should the Board decide to embed more of the 2004 forecasted margins in rates, Union requested that 75% of the forecast be put in rates with a symmetric deferral treatment, shared 75:25 in favour of the ratepayer, of any variances.

Board Findings

The Board continues to support the methodology approved in EBRO 499 with respect to embedding forecast S&T margins and the Long-Term storage premium in base rates on a 90:10 basis. However, in this regard and in respect of its finding above, amounts to be embedded apply to forecast 2004 amounts, not to EBRO 499 forecasts that were approved for the 1999 test year.

The Board finds that symmetrical variance account treatment of these revenues is appropriate to hold ratepayers and Union harmless from deviations between actual margins earned and those embedded in rates. The Board further accepts that any such variances be shared 75:25 in favour of the ratepayer.

4.4 OTHER ISSUES

There are two other issues falling into this section. The first of these relates to the concerns expressed, particularly by FONOM et al relating to storage allocations to the Northern and Eastern Operations area, while the second relates to Union's changes in presentation in successive rates cases, with respect to classifications of such items as S&T revenues and customer supplied fuel.

Background

The issue of storage allocations to the Northern and Eastern Operations area arose from the assumption by Union of these customers as part of its acquisition of Centra Gas.

Where changes in presentation are concerned, Union has in this proceeding stated that customer supplied fuel, which it receives from M12 and C1 customers, and which had been recorded as a storage and transportation revenue item in EBRO 499, is under current practice recorded as an offset to gas costs. Union stated that there is no financial net impact as a result of this change in presentation.

Position of the Parties

The appropriateness of Union's storage allocations, particularly to the Northern and Eastern operations areas was questioned.

FONOM et al cited evidence in EBO 195 to support its contention that Union had stated that former Centra customers would have access to Union's storage after Union acquired Centra. However, FONOM et al submitted that Union's evidence was to the effect that physical storage was not available on the same basis to Northern and Eastern customers as it is to Southern customers. FONOM et al characterized this treatment as unreasonable and unsustainable. In their view, this inadequate allocation of storage to Northern area customers was inappropriate given that a substantial portion of former Centra Eastern zone customers are downstream of Union's storage assets. FONOM et al also relied on Union's original unqualified undertaking regarding Northern access to storage and noted that Centra, prior to its acquisition by Union, was buying storage services for customer load balancing. FONOM et al admitted that they did not pursue this issue on the record, but stated that embedding the S&T margin would provide them with some benefits of Union's storage.

Board Findings

The Board is concerned that the allocations of physical storage and of deliverability rights do not seem to correspond to the cost allocations of these parameters to the various rate classes. Further, with respect to storage allocations to the Northern and Eastern Operations area, the Board notes concerns expressed by some intervenors. The Board directs Union to bring forward a justification of these allocations at its next rates proceeding.

The Board notes that Union's changes in presentation in successive rates cases, with respect to classifications of such items as S&T revenues and customer supplied fuel, seem only to add unnecessary opacity to parties' understandings of the evidence. The Board does appreciate that from time to time a reclassification of revenue and cost items may be appropriate. However, to aid parties in understanding the effects of any such reclassifications, where Union makes these changes, Union should present its evidence in the format provided in the prior rates case and in the proposed format in the current rates case along with a rationale for the proposed changes. This should provide parties with the transparency and Union with the flexibility to make changes that are appropriate.

As a general rule, the Board believes that where updated forecasts and data become available, after evidence has been prefiled but before the conclusion of the proceeding, these changes should be reflected in updates available to all parties and the Board, whenever practicable.

5. OPERATING AND MAINTENANCE EXPENSES

Background

Operating and Maintenance Expenses

Union provided an overview of its Operating and Maintenance ("O&M") expenses for the 2004 Test Year Forecast, the 2003 Bridge Year Forecast, and a 2004 Test Year comparison to EBRO 499 approved levels for 1999.

Union stated that its total net utility O&M budget was $361.9 million, before adjustments for capitalization, compressor fuel and other similar items. Union further stated that its evidentiary focus was on the main drivers of the O&M increase since its last rate filing. Union stated that if amounts related to benefits, pensions and post-retirement benefits, insurance costs, pipeline integrity, and regulatory compliance costs were backed out of gross O&M, and appropriate inflation adjustments made, the result is a gross O&M cost per customer in the 2004 budget less than it was in 1999.

Union presented a number of conclusions as a result of its analysis. These were:

1. that for those cost elements under its control, Union is forecasting cost increases which are substantially less than the projected Ontario 2003 and 2004 Consumer Price Index ("CPI") of 2% and 1.8% respectively;

2. while its customer base continues to grow, through productivity and efficiency gains controllable increases to operating costs

per customer are forecast to be at a rate lower than inflation; and

3. that its forecast 2004 O&M level is the amount necessary for Union to maintain safe and reliable service to its customers and to comply with increasing regulatory requirements.

Union noted that a number of the components of its O&M budget were discussed elsewhere in its evidence. These included cost increases related to human resources related costs, GDAR and rate rider billing functionality, the pipeline integrity management program, and recovery of costs from affiliates. The discussion of these components and findings related to them can be found elsewhere in this Decision.

In the area of insurance costs, Union reported that the energy industry has experienced significant increases in insurance costs, caused primarily by catastrophic claim losses and lower investment returns. Such increases amounted to100 to 200 percent over previous premium rates, despite larger deductibles and lower coverage limits. In addition, as a result of increased costs of litigation, bankruptcies, and the concern over corporate accounting and financial reporting, directors and officers' insurance rates were increasing in the range of 75 percent to 100 percent. Part of Union's response to these developments is its intention to self-insure, through the use of much higher deductibles than has been the case to date.

Union stated that it had forecast a 45 percent increase in its insurance costs for 2003, but no additional increase for 2004, through the use of substantially increased deductibles. Union further stated that insurance costs was one of the areas in which its affiliation with the Duke group helped to contain costs.

Union proposed to increase its recovery in rates of costs related to bad debt from an EBRO 499 Board approved level of $2.9 million to $13.3 million in 2004. This level represents a significant decrease from the actual 2002 level of $21.3 million.

Capitalized Overheads

Union stated that it capitalized a portion of its O&M costs following the same methodology used since EBRO 493/494. Union explained that this method is in accordance with generally accepted accounting principles and the Board's Uniform System of Accounts for Class "A" Utilities.

Capitalized costs represent the portion of Union's O&M overhead costs associated with the support of capital activities. Union noted that year to year variations in capitalized overheads can be attributed to the mix of capital versus O&M activities undertaken by the Company. In addition, variations in capitalized overheads can arise due to periodic changes in the methods used to allocate costs between activities.

Union stated that its forecast 2004 capitalization was $42.9 million, comprised of indirect capitalization of $38.4 million and direct capitalization of $4.4 million. Union defined indirect capitalization as overhead costs incurred by groups that support both capital and operating work, while direct capitalization represents costs that are incurred for specific capital projects.

Union explained that it capitalized a portion of its gross O&M expense to reflect the fact that many of the corporate support functions support employees that work on capital projects. For example, since a portion of the goods purchased by the procurement group is for capital projects, a portion of the costs attributable to the procurement group is recorded as being on account of capital.

Union characterized this approach as standard utility practice and stated that its capitalization method was consistent with both the Board's uniform system of accounts and with Generally Accepted Accounting Principles ("GAAP"). Union also stated that the method used was unchanged since EBRO 493/494. The only change for this application is that Union has conducted a review of the cost drivers and updated them to reflect the forecast 2004 activity levels and organizational structure. Union stated that this review hadn't been done for some time because under its PBR plan it wasn't necessary. Union explained that its level of capitalization in the

PBR period had been in the range of $9 to $52 million, declining in 2004 to $42.9 million. Union asserted that there had been approximately an 18 percent decline in capital activity in the 1999 to 2003 period.

Union then discussed the suggestion made in cross-examination, that it should maintain the cost drivers as they were in 2002, the last year for which actual results were available. Union rejected this proposition on the basis that it ignored the fact that 2004 drivers reflect the significant reorganization undertaken to align Union with Duke.

Positions of the Parties

A number of intervenors noted that since EBRO 499, and over the PBR period 2001-2003, Union's overall O&M expenditures had increased by substantially more than inflation, as reflected in the Consumer Price Index. In addition to the increase in O&M of $39 million over 2000-2003, Union has applied for a further 15.9% increase of $42 million for 2004. A considerable emphasis was placed by Intervenors on issues related to the fact that Union was leaving a PBR regime and entering a conventional cost of service model for 2004 rates. Suggestions were made that Union was shifting costs incurred under its PBR plan to the cost of service rate proposal. In addition to calling for reductions in various line items such as pensions, management fees, self-insurance, human resources, bad debt, and shared services, some intervenors suggested an "envelope approach" to determine the 2004 O&M budget whereby a base amount, the 1999 or 2003 actual O&M budget, would be used as a comparator to be escalated by an inflation factor. Another proposal was that the Board should compare Union's 2004 O&M request to what the O&M would have been if Union were still operating under a PBR plan.

A similar concern was expressed with respect to the changes in capitalized overheads. A number of intervenors questioned the low level of capitalization for 2004, to wit, 10.4% of gross O&M excluding compressor fuel, as compared to the 1999-2003 range of 12.6% to 13.8%. The suggestion was made that Union was attempting to inflate its revenue requirement to obtain a higher revenue base for a subsequent PBR proposal at Union's next rates proceeding. Parties urged that the capitalization of overheads be increased so as to be more in line with historic levels.

Parties also disputed the use of Union's updated cost drivers, submitting that O&M costs would be reduced by approximately $7 million if the current drivers were used instead. Cost drivers reflect the rationale behind the categorization of a given cost item as a element of overhead to be included as a portion of the revenue requirement, on the one hand or as a capitalized cost, forming part of the capital budget. Some Intervenors argued that there was no evidence to support the use of new or altered cost drivers and urged the Board to direct Union to use the existing methodology and to bring forward a study at its next rates case to justify any proposed change in the capitalization of overheads.

Some Intervenors argued that O&M costs related to the commodity price, such as bad debt and compressor fuel, should reflect the most recent (October) QRAM, to best reflect costs.

CAC complained that the presentation of the evidence in the case was confusing and made it difficult for parties to track changes in Union's O&M costs over the 1999-2004 period.

Some Intervenors rejected Union's claim for an increased provision for bad debt. They suggested that there was no demonstrated rationale for the increase sought. They suggested that the higher incidence of bad debt was related to specific market conditions which should not be assumed to be permanent features of Union's operating environment.

Union's Reply

Union argued that its claim for self-insurance costs reflected the lower coverage and higher deductibility terms Union had chosen in order to mitigate higher insurance premiums.

Regarding the use of the October 2003 QRAM to update commodity related O&M costs, Union charged that intervenors were being selective and strategic. Union submitted that there was no reason to assume that the October QRAM would be any more representative of actual 2004 commodity costs than any other QRAM.

With respect to bad debt, Union disputed that the increase, quantified by one intervenor as representing a 358% increase over the1999 level, was due either to volatility in the market or to retroactive charges, as had been suggested. Union stated that its risk management policy had shielded consumers from price volatility and noted that large retroactive charges were not billed until January 2003. Union argued that its bad debt forecast was based on the historic percentage of bad debt to billings and its estimated 2004 billings.

Union rejected criticism of its presentation of evidence in the case. It suggested that the complexity of the case, and the fact that it represented the first comprehensive cost of service examination in some years, made it difficult to present a simple evidentiary package.

Union rejected the characterization of its claims as representing an inappropriate shifting of costs from the PBR period to its proposal for rates for 2004. Union argued that although the proposed 2004 cost increases were largely beyond Union's control, ratepayers had nevertheless benefitted from the productivity increases Union had achieved under the PBR plan.

Union agreed "directionally" with the proposal to apply an inflation adjustment to its actual 2003 O&M costs in determining 2004 costs, subject to the proviso that further adjustments be made to recognize uncontrollable exogenous costs. Union stated that given these adjustments, real O&M costs per customer would be shown to have decreased.

Union strongly disagreed with an envelope approach for 2004 O&M costs, arguing that the Board had a detailed record in evidence that should not be ignored.

With respect to overhead capitalization, Union submitted that the methodology was the same as approved in EBRO 493/494, with cost drivers changed and updated to reflect 2004 capital expenditures. Union added that the CICA Handbook required an updating of cost drivers coincident with the making of the capital expenditures. Union noted that while it could not have updated the drivers under its PBR plan, it was now appropriate to do so, given that Union had just completed a depreciation study. Union concluded by claiming that its proposals were supported in the evidence by the summary and the capitalization study that Union had filed.

Board Findings

Operating and Maintenance Expense

The Board first notes that some intervenors have proposed an envelope approach to deal with the O&M budget. Under such an approach, a global O&M amount is approved to cover all such expenses for the period. While specific amounts are not allocated to specific O&M activities, the utility is expected to develop its own internal budget within the envelope. This approach is opposed by Union in this proceeding.

The Board believes that while an envelope approach may have merits in given circumstances, for this application it is more appropriate to establish approval levels for individual O&M expense items, given the detailed evidence that has been filed and tested and given that this is the first cost-of-service proceeding involving Union in a considerable period. The Board also believes that future cost of service and PBR applications will be informed by the comprehensive nature of this breakdown.

The Board accepts Union's O&M budget, with the specific exceptions outlined in this Decision. As indicated above, some of these exceptions are discussed in detail in other parts of the Decision, where an O&M item has been dealt with separately. The exceptions falling under this section are discussed in detail below.

Bad Debt Expense

The Board is not convinced that the increases in bad debt expense requested by Union have been adequately justified. The Board notes Ms. Elliott's statement that Union would historically be applying a one half of one percent write-off of total revenue to account for bad debts. The Board finds that Union has not provided convincing evidence as to why this historic level is no longer a reasonable level of protection. It is the understanding of the Board, based on the information provided in evidence, that $2.06 billion would be the appropriate 2004 revenue amount against which a recovery percentage would be applied. Accordingly, the Board will allow

Union to recover one half of one percent percentage of the aforementioned amount, or $10.3 million in bad debt expenses in rates for 2004. This represents a reduction of $3.0 million from the $13.3 million level of recovery requested by Union.

Other Matters

School Boards urged the Board to include, in its examination of Union's O&M budget, the arguably comparative costs of EGDI. While benchmarking each Utility against the other may have merit in some instances, the Board does not consider it reasonable or appropriate to require that an Applicant justify its costs relative to those of any other individual operator, without convincing evidence that the basis of comparison is fully appropriate and reasonable. In this case the Board has no such evidence before it, and except in the most general terms, has not considered Union's position on any aspect in comparison to that of EGDI or any other utility.

The Board also notes CAC's request for a greater standardization of filing requirements and formats for gas utility rates applications. The Board considers that there may be merit in reviewing the way in which gas rates applications are organized and filed and will consider appropriate approaches to dealing with this matter.

The Board notes the concerns that have arisen in this proceeding related to a perceived discontinuity between many of Union's costs in the PBR period and the 2004 cost of service re-basing test year. Union took the position that this apparent discontinuity arose for a variety of reasons, including the necessity for it to manage to achieve acceptable earnings levels in a PBR environment. However, a number of intervenors argued that this phenomenon is the result of Union's loading costs into a re-basing year that should have been recognized during the PBR period.

Issues respecting the transition of Utilities between PBR and cost of service regimes are of interest to the Board, and the Board will consider these matters in an appropriate forum.

Capitalized Overheads

The Board finds that the Applicant has not provided sufficient justification for its proposal to change the cost drivers used to determine capitalized overheads. While the Applicant provided some evidence reflecting the changes sought, there was little or no detail substantiating or justifying the transition of items which had previously been capitalized into operating expense. Changes of this nature, which effect the very basis of the revenue requirement, must be appropriately supported with sufficient evidence and rationale to allow the Board to make a reasoned assessment of the proposal. Such changes cannot be solely within the purview of the Company. Accordingly, the Board directs Union to continue the use of the current cost drivers to calculate the capitalization of overheads in the 2004 test year.

The Board expects that the impact of this recalculation would be approximately a seven million dollar reduction in 2004 expenses and revenue requirement, partially offset by appropriate adjustments for the corresponding increases in capitalization levels. The Board expects Union to file, as part of the implementation process for this Decision, a complete summary of the adjustments it has made to the revenue requirement to effect this aspect of the Decision.

Should Union wish to make use of new cost drivers in future proceedings, the Board will expect Union to file comprehensive and clear justification for such proposals, including full details as to the impacts on the revenue requirement that will result from their adoption and a coherent rationale for the change in treatment.

O & M Costs Related To Human Resources

Background

Union stated that the purpose of its evidence in this area was to provide an explanation of its Human Resource (“HR”) activities and related costs, and to explain the increases in these costs from the EBRO 499 level of $24.6 million to an estimated $50.6 million level for 2004. Union argued that the approximate doubling of this amount since 1999 was attributable to costs caused by market factors beyond Union's control. Union added that cost increases of this kind have been experienced by many comparable companies and its methods of accounting for such costs are in accordance with GAAP, and are as recommended by its accounting and actuarial professional consultants.

Union stated that the increase in Human Resource costs was primarily due to costs associated with Benefits, Post Retirement Benefits and Pensions. Union filed a letter dated May 8, 2003 from its actuary, Towers Perrin, evidencing these increases. The overall cost of salaries and wages was given considerable attention during the proceeding because this cost did not change significantly relative to EBRO 499, in spite of a significant decrease in full-time equivalent employees ("FTEs") that had taken place since EBRO 499.

Benefits

Union stated that its employee benefit costs, exclusive of pension and post retirement benefits, had increased from the $23.3 million EBRO 499 level to roughly $25.5 million. Union justified this level of increase by noting that over the 1999 to 2004 period, its costs of benefits per FTE had risen by approximately 28%. Union attributed this rise mainly to health cost increases. Union cited the increased use of benefit programs, especially its drug benefit plan, medical cost inflation, and government cost shifting from the public to the private sector as underlying factors for this increase. Union noted that from 1999 to 2002, extended health care and dental costs had increased by an average of 18% per year. An increase of 13% is projected from 2003 to 2004, based on industry trends.

Towers Perrin commented on these increases and stated that they were consistent with its benchmark data of medical and dental experience in Canada, across all industries for all types of group health and welfare benefit plans. Towers Perrin also stated that prescription drugs, which account for 70% to 80% of a company's health plan costs, are both the largest and the fastest growing component of these costs, growing annually at a rate of 18% to 20%.

Union stated that it manages these expenses responsibly and ensures that expenses are prudently incurred by having them scrutinized by competent professionals. Union submitted that it is getting good value in this area, but is subject to the same upward pressures as experienced by all others in the present economy. Union characterized its health and welfare benefits plan as being in the median, a “run-of-the-mill” plan. In this context, Union noted Mr Witts’ comment that “It’s a good plan. Is it a Cadillac gold-plated plan? No, by no means. In fact, the plan, as it will be applied in 2004, is a redesigned plan that introduces some cost-sharing elements, a greater level of cost sharing with employees, and it was benchmarked in the median of Union Gas’ comparator group of companies.”

Post-Retirement Benefits

Union stated that post retirement benefits had increased from the $1.2 million level approved by the Board in EBRO 499 to roughly $5.4 million. Union attributed this increase to two factors. The first is the revised CICA methodology of “accrual” accounting, which became effective January 2000. This methodology required that the future costs of retiree benefits be accounted for during the working lives of employees, as opposed to the former “pay-as-you-go” approach, under which retiree benefits were recorded as a cost when the expenses were actually incurred. Union stated that this accounting change resulted in a one-time increase of approximately $5.3 million in the annual expense for post-retirement benefits. Union noted that this matter had been discussed in RP-1999-0017 and that in its Decision in that proceeding, the Board had stated its acceptance of this changed practice for rate-making purposes. The second factor cited by Union in support of this increase was the decline in long-term bond yields over the 1999 to 2004 period and the increased life expectancies of retirees.

Towers Perrin also stated that the discount rate used to determine post-retirement benefit expense had declined in 2003 to 6.50% from 7.25% in 2002. Towers Perrin noted that a reduction in this discount rate results in an increase in the present value of future benefit payments, which in turn results in an increase in post-retirement benefits accounting expense. Towers Perrin also noted that the ultimate cost of providing extended health care benefits to retired employees will depend, in part, on how much the cost of medical services increases. Towers Perrin stated that in determining Union’s 2002 expense, the cost of medical services was assumed to increase by 5% per year, which Union continues to believe is a reasonable long term assumption. However, Towers Perrin also noted that based on recent experience, it is likely that these costs will increase at a greater rate in the short term, and, accordingly, the assumed rate of increase was raised to 10% in 2003, grading down to an ultimate rate of 5%. Towers Perrin stated that it believed both these changes were consistent with its benchmark data for other large Canadian organizations.

Pensions

Union stated that its pension costs had increased from $5.1 million approved by the Board in EBRO 499 to an updated level of approximately $19.6 or $19.7 million in the 2004 budget. Union attributed this increase mainly to two factors. The first of these was negative returns on pension fund assets due to declines in the equity capital markets and the second was increased pension obligations as a result of a declining trend in long-term bond yields.

In its letter, Towers Perrin supported these increases, stating that defined benefit pension accounting expense had increased significantly over the last business cycle, primarily as a result of negative returns on pension fund assets due to continuing declines in equity capital markets, and increased pension obligations as a result of a declining trend in long-term bond yields.

Towers Perrin also commented on Union's use of "smoothing methods" in order to control the year over year volatility of pension accounting expense, noting that two different smoothing methods were used. The first, as permitted by Canadian accounting standards, results in experience gains and losses not being immediately recognized in pension accounting expense, but phased in over a three-year period. The second, as permitted under accounting standards, is the application of a so-called "10% Corridor" in recognition of actuarial losses resulting from changes in actuarial assumptions and experience losses. This means that the full extent of these changes is not recognized immediately in expense, but rather a portion is deferred into the future.

Towers Perrin noted that a number of actuarial assumptions are used in determining the accounting expense for pensions. One of these is the discount rate which is used to determine the present value of expected future benefit payments. Towers Perrin stated that in determining the 2002 pension expense, the discount rate used was 7.25% per year, while for 2003 it declined to 6.50%. Another key actuarial assumption is the expected rate of return on assets, which is used to determine the expected investment income that will be earned by the pension fund assets. For 2002, the expected rate of return on assets was 8.5% per year, while for 2003 it declined to 7.75% per year. This decrease was attributed by Towers Perrin to the recent decline in interest rates and the downturn in capital markets. Both these changes would have the effect of increasing Union's pension costs. Towers Perrin stated that both were also consistent with its benchmark data for other large Canadian organizations.

Towers Perrin also noted that the declines experienced in capital markets in recent years have already had an adverse impact on Union's pension fund assets and the financial position of Union's pension plans, stating that for fiscal years 2001 and 2002 combined, the annual rate of return on the pension funds was approximately -20% compared to an expected rate of return of approximately 16%, implying a shortfall in the return on assets of 36%. Towers Perrin further noted that the resulting experience losses of more than $100 million will result in an increase in pension expense in future years.

In comparing this performance relative to that of other large Canadian organizations, Union stated that, based on information provided by RBC Global Services, the actual rate of return on the Union pension funds for the two year period ending September 30, 2002 was -18%, while the median rate of return over the same period for Canadian pension plans with pension fund assets of greater than $250 million was -11%. This relative under performance of approximately 7% compared to the median fund was attributed to relatively poor returns on international equities and a relatively greater allocation of assets to international equities at a time when this asset class underperformed in general.

Union specifically addressed the question of whether or not this level of performance constituted imprudence, taking the position that a determination on this matter could not be made simply by looking at what had happened with the benefit of hindsight, and using the losses described above as dispositive of the issue of prudence.

Union stated that the only basis upon which such a determination could be made was if there was evidence in this proceeding that, at the time the decisions had been made, either the allocation of assets in international equities, or the selection of the particular equities in question was so imprudent that a reasonable pension committee ought not to have followed the advice and the recommendation of its professional fund managers. Union stated that there was no evidence on the record that came even remotely close to permitting such a conclusion. Union expressed the view that its pension plan was well-run and the fact that Union, along with everyone else, experienced investment losses, was, of itself, no basis for denying recovery of the funding costs that are required by law to ensure that promised benefits are available when employees retire.

Union supported this position by reviewing two regulatory decisions. These were, first, a decision of the Federal Energy Regulatory Commission ("FERC") in the New England Power Company case. The second case reference was to the Board's findings in the RP-2001-0029 case where the issue of the prudence of the cost consequences of the Alliance/Vector contract between Union and Alliance and Vector was reviewed.

The FERC decision was quoted, in part, as follows:

> "In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses."

The Board's RP-2001-0029 Decision was quoted, in part:

> "Utilities that are obligated to take action to address operational requirements must be able to do so with some confidence that their actions will be judged on the basis of circumstances obtaining at the time they are compelled to make the decision, not on the basis of circumstances which emerged afterward. This principle is consistent with the NRRI guidelines."

Positions of the Parties

Wages and Salaries

As indicated earlier in this section, Intervenors expressed concerns with respect to an increase in salaries and wages per employee. First, concern was expressed in the increase in light of the fact that Union had eliminated a significant number of positions after 1999. Second, Intervenors raised issues respecting the magnitude of the increase. CAC calculated the increase to be 17.2% since 1999. A number of intervenors noted that this increase significantly exceeded the inflation over this period. Citing one large increase in this item, of 6.4% per FTE from fiscal 2002 to 2003, some intervenors alleged that Union was attempting to shift PBR costs to a cost of service year by providing wage and salary increases below the rate of inflation for the period 1999-2002, and above the rate of inflation thereafter. A number of intervenors proposed that the increase in this item be more closely related to the expected 2004 inflation rate. In addition, concern was expressed respecting the increase, given the fact that Union had eliminated a significant number of positions since 1999.

Incentive Programs

The main issue of concern in this area was not whether these payments were appropriate, but rather who should bear the costs of the incentive programs. The argument was made that because over half of such payments (53%) are tied to profit, and profit benefits only the shareholder, that the cost of incentive payments should be borne by the shareholder. Intervenors suggested that a reduction of $5.1

million in O&M costs would address this concern. A further issue, raised by IGUA, was that since not all incentive payments might be made, it was unfair to embed 100% of forecasted incentive compensation in rates.

Pensions

The suggestion was made that Duke Energy as part of its due diligence investigation would have identified and taken into account of Union's pension plan liabilities at the time of its acquisition of Union. Further, some Intervenors expressed concern that while ratepayers are being asked to fund pension plan deficits, there is no corresponding benefit when the pension plan shows a surplus. VECC, CME, and Energy Probe argued that pension costs relating to PBR years should be a shareholder responsibility and not shifted to ratepayers in a post-PBR period. CAC added that Union's 2004 claim should be reduced from $21.4 million to approximately $7 million on the basis that Union's shareholder must be responsible for the investment decisions made, which lead to the shortfall and that the shareholder should not benefit from accounting rules changes that allow pension losses to be shifted out of period. LPMA argued that the Board should deny the $4.9 million increase, relative to 2003, in the 2004 provision for pension losses. School Boards argued that it was inappropriate for Union to fund the costs of increased early retirements, arising from Union's 1999-2000 restructuring, from pension plan assets, which were in a surplus position at the time; School Boards submitted that the surplus should have been used to offset investment losses in 2001 and 2002. Other proposals included requiring Union to report on how other jurisdictions treat pension expenses, closing defined benefits programs to new entrants, smoothing the impact of pension expenses over a five-year period, and allocating ratepayers, in each year, a fixed or formulaic amount that represents the long-term annual cost of funding pensions.

Union's Reply

Regarding wages and salaries, Union stated that while it only had FTE figures on a forecast basis for 1999, 2003, and 2004, which were developed for regulatory filings, Union had provided estimates of FTEs at year end for each year based on available data. Union replied to CAC's concern that the average salary had increased by

17.2% over the period 1999-2004, arguing that this increase was the result of inflationary and competitive pressures and an increase in the skill sets and compensation levels of employees. Union added that the growth in salary costs had not exceeded the growth experienced by comparable Canadian companies as evidenced by a comparator group of about 100 Canadian companies. Union continued that had it not decreased its FTEs, the 2004 O&M forecast would have been $32 million higher than proposed. Therefore, the $32 million constituted a ratepayer benefit due to a sustainable improvement in productivity achieved under its PBR plan. Union submitted that increases in compensation levels in 2003 and 2004 reflected the fact that Union's ability to attract and retain highly skilled employees had deteriorated previously and the increases ensured that Union would not fall further behind other companies in the competitive labour market.

With respect to incentives, Union agreed with the proposition that there is no certainty these will be paid, but argued that this ignored the purpose of such payments: to motivate employees to achieve or exceed targets. Union stated that if such payments are not made, the savings is not 100% to the shareholder's benefit, because this would indicate the failure to achieve targets, a situation that leaves higher costs in Union's O&M. Union added that while exceeding targets related to financial performance in the test year would provide increased benefits to the shareholder, where such success is due to sustainable productivity increases, there will be a ratepayer benefit in subsequent years. Union continued that even if targets are not met, ratepayers benefited from rates set as though targets had been met. Union concluded that ratepayers also benefit indirectly from having a productive and financially healthy utility, by receiving better service, paying a lower cost of capital, and having more reliable and responsive owners.

On ratepayers sharing in a pension plan surplus, Union stated that ratepayers receive service in exchange for paying rates which recover reasonable costs, and, as such, ratepayers are not entitled to surpluses. Union submitted that there was no unfairness or asymmetry in its recovery of pension plan deficits if the deficits are prudently incurred and accounted for in accordance with GAAP. Further, Union argued that when pension plans are in surplus, Union can take a contribution holiday and ratepayers benefit from the attendant reduced O&M costs.

Union stated that increased pension costs were the product of two factors beyond its control: market conditions and the application of GAAP. Union claimed that its treatment of pension costs during the PBR period was consistent with the *Pension Benefits Act*, the CICA Handbook, and the uncontradicted evidence of Union's professional advisors.

In support of its pension plan proposals, Union noted that the Board's RP-1999-0017 Decision had approved Union's proposal (in accordance with GAAP) to change from a cash basis to an accrual basis for pensions and post-retirement benefits, in order to match costs to the period in which the obligation arose. Union submitted that amortization of costs benefits ratepayers by reducing volatility. Union added that the cost of pension benefits in 2004 is not the asset value losses in 2001 and 2002 but rather the unfunded liability that professionals deem necessary to recover in the year so that the plan will delivered its promised benefits at maturity.

Union argued that the "variances arising from changing economic conditions" for which cost recovery was disallowed under PBR, referred to changes in economic growth, consumption, interest rates, and the like. Union stated that while ratepayers had been insulated from them, Union had borne the costs of such changing economic conditions.

The argument that Duke knew (or should have known) the state of the pension plans at the time of acquisition was without merit because Duke was entitled to expect that the utility would be allowed to recover prudently incurred costs such as pension deficits.

Regarding the funding of increased early retirements out of pension assets, Union argued that in 2001, in its RP-1999-0017 Decision, what the Board had denied was recovery of terminations costs incurred in 1999, a year for which rates had already been set. Union submitted that this disallowance was due to the costs being incurred out of the 2000 test year, a far different matter than voluntary early retirement. Union stated that if there is an increased take up of voluntary early retirement during restructuring, pension costs and plan liabilities also increase: for a plan initially in equilibrium, this will give rise to unfunded liabilities which increase pension costs in a given year under GAAP. However, if a plan is in surplus, increased liabilities less than the surplus do not give rise to unfunded liabilities or pension costs. Therefore, Union argued that its accounting treatment was not only appropriate, but required, since contributions to a plan in a surplus position are effectively prohibited.

Board Findings

The Board notes that Union is requesting increases in all areas of Human Resources costs for 2004. The Board will deal with each of these individual elements of the request.

Salaries and Wages

Union's salaries and wages are shown in Exhibit N6.11 to have increased by 17.2% when comparing the 2004 forecast costs to the EBRO 499 level on the basis of average salary per FTE. The Board notes that the level of increases averages 2.5% for all years except 2003 over 2002, for which it is 6.4%. The Board shares the concerns of a number of intervenors regarding the anomalous nature of this 6.4% increase, compared to the increases in the other years. Such a sharp increase in this area of management should be supported by specific evidence providing a rationale for the magnitude of the divergence from previous years. The Board concludes that Union has failed to provide a sufficient evidentiary basis for the totality of the claim. Accordingly, the Board is in agreement with the proposal of CAC that Union be allowed an average annual increase in these costs of 2.5% annually for the 2004 test year versus the EBRO 499 level of cost recovery. The Board will therefore allow a 2004 recovery of $143.7 million, representing a reduction of $5.2 million from the level proposed by Union.

Incentives

The Board is in agreement with Union's use of incentive payments as a legitimate element of a total compensation package offered to attract and retain qualified managers and staff in a competitive market for human resources. The question which the Board must consider is the extent to which ratepayers benefit from, and should bear the cost of such payments.

The Board finds that the use of incentive payments is a reasonable element of Union's employee compensation and benefits ratepayers over the longer term by allowing Union to compete for high quality human resources, leading to a more efficient operation of the Utility.

To the extent possible, the operations of the Utility should be consistent with good management in other sectors of the business community. As indicated elsewhere in this Decision, the Utility should be in a position to manage its business confidently and conventionally. Incentive programs are a common element of business management in all sectors of the economy, and have come to be regarded by employees, and prospective employees, as an essential element of compensation. Unless the incentive programs can be shown to be extravagant or otherwise objectionable, they should be supported as part of the revenue requirement. It would be perilous to create a situation in which the gas distribution utility, alone among business categories, could not effectively attract and keep quality employees through the offering of reasonable incentive programs.

The Board therefore approves the request for the incentive component of total compensation and makes no additional adjustments to salaries and wages as a result of its consideration of this item.

Benefits

Where benefit costs are concerned, the Board accepts the evidence presented by Union, supported by Towers Perrin, that benefit costs per FTE have risen by approximately 28% since 1999, due mainly to health cost increases. This evidence was not credibly challenged. The Board also notes that the total number of FTE's over the same period has declined by approximately 400. Accordingly, the Board finds that the net impact of the above variables results in an increase of $2.2 million in benefit cost over this period and accepts that the projected 2004 benefit cost of $25.5 million is reasonable.

Post Retirement Benefits

The Board also accepts the evidence presented by Union, supported by Towers Perrin, that the cost of post retirement benefits has increased in the period from EBRO 499 to 2004, due mainly to changes in accounting rules and discount rate assumptions. Therefore, the Board finds the request of $5.4 million in the 2004 revenue requirement to be reasonable under present circumstances.

Pensions

Where Pension costs are concerned, the Board accepts that these costs have increased for the company as a result of negative returns on pension fund assets due to a decline in equity markets and also due to increased pension obligations as a result of a declining trend in long term bond yields.

The Board notes the concerns of intervenors regarding the negative returns on pension fund assets, but also notes that the Board has been provided with no evidence to support the position that the achieved level of performance was due to imprudent actions by the Company. The Board also finds that increased obligations due to a declining trend in long term bond yields are beyond the immediate control of the Company. The Board therefore approves the pension cost component of the employee compensation package.

6. RATE BASE, CAPITAL BUDGET

Union's Application

Union is seeking Board approval for a proposed capital budget of $158,060,000 and a rate base of $3,058,798,000 for 2004.

The proposed 2004 rate base of approximately $3.1 billion is higher than the 1999 rate base by approximately $0.4 billion. Union stated that the rate base increase over the five years was mainly attributable to Union's commitment of approximately $200 million in annual capital expenditures and increases in working capital for gas in inventory and gas used to balance bundled direct purchase customers.

2004 Capital Budget

Union's updated prefiled evidence provided actual capital budgets for the years 1999-2002 and forecasted capital budgets for 2003 and 2004 as shown in the table below.

$ millions	2004 Budget	2003 Budget	2002 Actual	2001 Actual	2000 Actual	1999 Actual
Total	158	139	193	218	203	222

For 2004, the original forecast capital expenditures were $217.691 million. The updated forecast reflects reductions in storage, transmission, distribution, and general capital expenditures, with the largest reduction in transmission projects.

Union stated that its 2004 capital budget was approximately 24% less than average capital expenditures over the period 1999-2002. Union noted that the major difference between the budgets of 2003 and 2004 and previous budgets was that transmission expansion spending, historically approximately $40 million per year, was low for 2003 and there was no provision for such projects for 2004. Union stated that the 2003 and 2004 capital spending reflected a general declining trend rather than being abnormally low.

With respect to LPMA's suggestion made during the course of the proceeding that Union consistently overforecasted capital spending by $46 million per year, Union replied that it had forecast a $60 million reduction for 2004 and rejected further reductions. Union added that contingency provisions should remain intact.

Customer Attachments

Union's actual 2000-2002 attachments, along with its updated forecasts of 2003 and 2004 attachments, are provided in the table below:

	2000 Actual	2001 Actual	2002 Actual	2003 Forecast	2004 Forecast
Total	24,437	21,367	29,785	25,923	27,015

Union stated that the 2002 actual attachments were "considerably higher" than Union had forecasted based on Canada Mortgage and Housing Corporation ("CMHC") reports. Union's expectations of interest rate increases in early 2002 did not materialize to slow construction and there were more conversions to gas heating than Union had expected.

Union did not expect the situation prevailing in 2002 would continue. As a result, Union's original attachment forecasts for 2003 and 2004 were 19,758 and 20,310 respectively. Union attributed the increases in revised forecast customer attachments to:

1. receipt of updated housing start information from CMHC,
2. five months of 2003 actuals,
3. lower than expected interest rates,

4. high consumer confidence,
5. strong demand in the Greater Toronto Area ("GTA") spilling over into Union's service area, and
6. continued diligence in monitoring home oil storage tanks.

In response to CME's suggestion that Union was overforecasting attachments, Union submitted that test year forecasts should not be based on historical averages, and that the evidence showed that over the past nine years Union's forecasts had been accurate, exceeding actuals by an average of 2.2%.

Major Pipeline Facilities

In its initial prefiled evidence, Union stated that the Dawn-Trafalgar pipeline capacity would not meet demands for either the 2003-2004 winter or the 2004-2005 winter, thereby necessitating the use of non-facility capacity, such as a winter peaking service ("WPS"). For the 2003-2004 winter, 44,000 GJ/d of non-facility capacity is required. For 2004-2005, Union planned to build an 18 km pipeline from Brooke to Strathroy. Even with this facility, 37,000 GJ/d of WPS would be required. The Panhandle system would also require additional facilities - looping and modifications to two metering and regulating stations - for the 2004-2005 winter.

Updated design day demands have now allowed Union to defer the Brooke-Strathroy project to the winter of 2005-2006 and to delay the Panhandle projects. The updated non-facility requirements are 33,200 GJ/d for winter 2003-2004 and 92,800 GJ/d for winter 2004-2005.

Storage Development Projects

Union proposed to install gas chromatographs at each storage pool's measurement and control station to improve the accuracy of energy measurement at each individual pool at a cost of $2 million in 2004. Union also proposed to spend $1.684 million on other storage projects in 2004.

Union argued that gas chromatographs were required to reconcile transactions on an energy units basis. Union dismissed suggestions that it had delayed the project until it was out of the PBR plan, arguing that the issue first arose internally in September 2002 and an internal committee recommended the project in 2003. Final approval for inclusion of the project in the 2004 budget was given on March 25, 2003. Union added that it had spent significantly more on capital projects annually under PBR over the period 2001-2003 than it was forecasting to spend in 2004.

The suggestion made by VECC to purchase the chromatographs over a two-year period is without merit in Union's view given that the project's purpose is to monitor energy in Union's entire system, an impossibility with only half the chromatographs necessary.

Pipeline Integrity Including Program, Spending, Rate Treatment

Background

In response to Ontario Regulation 210/01 enacted in June 2001, Union expanded its Pipeline Integrity Management Program ("IMP") to cover all steel pipelines operating at a pressure of 30% or more of the Specified Minimum Yield Strength ("SMYS"). The regulation is administered and enforced by the Technical Standards & Safety Authority ("TSSA").

Union will complete the development of its IMP and establish the priority of the pipelines to be included in the IMP's scope by the end of 2003. Union's IMP monitors pipeline condition, assesses risks, and ensures reliability.

Union started a 10-year plan in 2002 to assess the condition of 2,800 km of pipeline mainly by electronic in-line inspection ("pigging"). Because many parts of the system were not designed to accommodate pigging devices, significant work will be required to modify such lines.

Planned expenditures for 1999, 2003, and 2004 for IMP, along with actual 2002 expenditures are shown below.

IMP Spending				
Expenditures ($000)	**1999 Plan**	**2002 Actual**	**2003 Plan**	**2004 Plan***
Capital	3,066	9,859	6,519	9,146
O&M	1,088	2,969	2,780	4,700

The rate impact of actual incremental costs, directly related to the new Regulation, for 2002 was $2.189 million. Union forecasts this expenditure to increase to $3.358 million in 2003. Union seeks to “dispose of the forecast $3.358 million deferral account balance to customers.”

With respect to its pipeline integrity management program, Union declined to respond to concerns that its program had not been independently audited and could turn out to be revenue enhancing if the deferral account is closed. Union reiterated that its program had been audited by the TSSA.

Union cited the RP-1999-0017 Decision in which “... the Board found that if a non-routine adjustment became a recurring event, that adjustment or cost should be included in rates.” Union also cited the RP-2000-0040 Decision where the Board expressed concern over “the proliferation of deferral and variance accounts.”

Union repeated that it was now in the third year of a ten-year program with costs now known and forecasted through 2011, a forecast that Union feels is credible. Union disagreed with the retention of a deferral account for the program and took issue with the proposal that the deferral account be asymmetric.

Union stressed that these were regulatory compliance costs that Union was entitled to recover in full “as long as there is no question of imprudence, which there is not.” Union argued that should the Board determine that a deferral account be maintained for the program, the account should be symmetric.

Union replied to the suggestion that 2004 IMP costs should be amortized over four years by stating that this proposal, advanced by some parties, would increase O&M costs, extend the program to beyond ten years, and was “inconsistent with the approach approved and taken in the PBR term." Further, it was unnecessary, given the relative stability of the costs over the program's lifetime.

Finally, Union submitted that the capital program forecast should contain an amount for contingencies to account for potential variability in the estimated costs, a normal budget practice.

Parkway Commitment

Union stated that subsequent to implementing the TCPL turnback policy, obligated deliveries at Parkway by direct purchase customers consisted of approximately 50% TCPL capacity, assigned by Union, and 50% firm capacity arranged by the customer. Since the forecast of summer 2002, there has been a "fairly significant" return to system by bundled direct purchase customers who return only the TCPL capacity - approximately 50% of the DCQ needed to serve them - to Union. Union therefore has incremental peak day and gas supply requirements.

Union is currently in negotiations with marketers regarding migration of their contracts to the unbundled service. Although Union currently has no customers for its unbundled service, if any customers choose this service, Union will require a Parkway call back for the 2003-2004 and the 2004-2005 winters. Assuming the current Dawn-Trafalgar load duration profile, forecast weather, and an average call volume per contract of 5,300 GJ (140 10^3m^3), Union calculated that a 22-day Parkway call back would cover the first 41,500 GJ/d (1,100 10^3m^3) of unbundled Parkway DCQ. Unbundled volumes in excess of this amount would require incremental costs to maintain the supply capacity of the Dawn-Parkway system. Union will update the 2004-2005 volumes in spring 2004 and will review the provisions annually.

Rate Rider Functionality

Union noted that its current retail Customer Information System ("CIS") was developed during the mid-1990's. Union explained that rate rider functionality was excluded from the system at that time for two reasons. Union's then existing billing system did not have rate rider functionality, and Union had generally been able to obtain rate approval so that rates could be implemented very close to January 1 in any year for which rates were being set.

Union stated that changes had occurred since the current CIS implementation was completed in July 2000 which justified rate rider functionality. Natural gas prices had become significantly more volatile, most notably in the period between February 1, 2003 and March 17, 2003, when Union's forecast of 2003 year-end deferral account balances changed from approximately $9 million to $141 million.

Union stated that it had not been able to show the approved rider separately and had to blend the rate rider with the commodity rate. Union had to send a notice to advise customers of this charge.

Union further stated that customers have expressed a strong dislike for out of period charges, or retroactive rate adjustments.

Union noted that it had applied for and received approval for a commodity rate rider, which recovered significant deferred inventory revaluation and PGVA debits. However,
Union asserted that, while not stated explicitly, it appeared to Union that CEED was of the view that large deferrals should be dealt with through an explicit rate rider, similar to the way EGDI treats such amounts.

Union noted that it was proposing to modify its QRAM process to include the prospective recovery of gas cost deferral account balances. Union added that it would separately identify the deferral recovery adjustments as rate riders on the customer bill if the related costs are approved by the Board.

Union stated that the cost of modifying its CIS system to include rate rider functionality was assessed by Alliance Data Systems (formerly Enlogix), the owners of the system. Union stated that the functionality it was seeking to implement would allow for rate riders that could be applied to either the upstream transportation, storage, commodity or delivery rates. It would also allow Union the ability to retain its database related to such charges for up to 24 months.

Union noted that several intervenors claimed that rate rider functionality was not necessary, or alternatively, should be developed at Union's cost.

Union noted that the cost of rate rider functionality is driven by the need for additional data base capacity and updates to the existing software to effectively store the additional data, while maintaining processing speed.

The proposed amendments to the QRAM methodology, based upon a prospective recovery of commodity related deferral account balances, require the use of rate riders. Union also rejected the suggestion that the limitations of the present billing system were unknown in 1997, or that any representation had been made that the new system would have additional functionality at no additional cost.

Union indicated that the total cost to implement a rate rider for each of the primary rates is $3.8 million. Union argued that the $3.8 million cost should not be amortized over three years since $3.35 million falls under the ADS contract, and will be incurred in 2004.

Positions of the Parties

Customer Attachments

Some intervenors disputed Union's 2003 customer attachment forecast of 25,923, arguing that a 13% decrease with respect to the actual attachments in 2002 was unwarranted given that the January-September 2003 actuals were 23% higher than the January-September 2002 actuals.

Some intervenors took issue with Union's position that the five-year mortgage rate was "a full point higher in 2003 than it was in 2002," citing Bank of Canada data showing that the average five-year mortgage rate for January to October 2003 of approximately 6.5% was less than the 2002 average rate of 7.0%. LMPA also noted that the 2002 data showed that 36% of M2 and R1 attachments were added in the fourth quarter. In its view these factors lead to the conclusion that the 2003 attachments should be increased to 33,322. LPMA and VECC proposed that the actual 2002 attachments of 29,785 be used for 2004. The overall impact of their proposals would be to reduce the 2004 revenue requirement by more than $350,000.

CME argued that Union had overestimated the 2004 attachments and hence overstated its 2004 capital requirement. CME urged the Board to approve a customer attachment budget for 2004 based on attachments of no more than 25,196. CME asked the Board to reduce Union's capital request by at least $1.5 million.

Pipeline Integrity Program

Intervenors noted that forecasted costs for the 10-year expanded program were $85.45 million on capital and $61.54 million for O&M. Most argued that the Board must determine the most appropriate way to recover the program costs that have been prudently incurred. Given the magnitude of forecasted costs and the fact that the TSSA did not audit its cost effectiveness, intervenors urged that Union be required to have its plan independently assessed. Intervenors also felt that the $706,000 capital contingency component of Union's forecast should be removed.

One intervenor argued that Union should complete the program over 20 years rather than over 10 years to reduce the cost impacts.

Most intervenors felt that past differences between forecast and actual spending, the large contingency amount included in the forecast, and the ability to defer costs, all indicated the need for deferral account treatment. There was no issue with the recovery of the $3.3 million balance in the deferral account in 2003.

Most intervenors proposed that the O&M costs relating to IMP should be amortized over 4 years.

Storage Development Projects

VECC questioned whether Union's proposal to spend $2.0 million on the gas chromatographs project was reasonable. VECC noted Union seemed to have no problem with measurement accuracy over the 2000 to 2002 period, during which actual capital expenditures were 18% below forecast. VECC stated that Union had not shown the gas chromatograph project to be either necessary, or of benefit to ratepayers, citing Union's admission under cross-examination that the existing averaging method and measurement system was appropriate. VECC stated that this project should not be approved until Union has provided evidence of its need for greater accuracy. Should the Board approve this project, VECC and LPMA proposed that it should be carried out over two years to lessen the rate impact.

Rate Rider Functionality

Two intervenors supported the need to develop rate rider functionality within Union's billing system but argued that the cost of $3.8 million should be amortized over three years.

The intervenors who rejected rate rider functionality argued that Union had not undertaken any market research to determine ratepayers' desire for the additional information and that the benefit of the additional details may not outweigh the cost of $3.8 million. These intervenors also noted that the amendments to the QRAM process to recover commodity deferral account balances prospectively may overcome the need to develop the rate rider.

Other

LPMA submitted that the Board should not allow contingency amounts and that Union should update various figures using more up-to-date information.

LPMA noted that over the period 1999-2002, when the budget forecasts were prepared in the fall for the subsequent year, Union had consistently overforecast its capital budget, and hence its rate base, on average by 18.1% or $46 million per year. LPMA was concerned that there could be reductions to Union's proposed 2004 capital expenditures, exposing ratepayers to significant risk of underspending by Union.

Board Findings

Customer Attachments

The Board notes the significant annual variation in the actual customer attachments for the period 2000 to 2004 (forecast), from a low of 21,367 in 2001 to a high of 29,785 in 2002, a year in which robust housing starts favoured new customer attachments. The Board has difficulty in accepting VECC's proposition that the actual forecast for 2003 should be raised by 30.3 percent from 25,923 to 33,782. However, based upon Union's experience for January to September, 2003, the 2003 total will be increased. Any additional increase to customer attachments in 2003 will affect the total number of customers attached in 2004, and therefore the corresponding forecast of gas volume consumption.

The Board finds no support for the position of CME that the 2004 customer attachments should be reduced to 25,196, the average for the period 2000 - 2002.

The Board finds the arguments of LPMA to be persuasive and will increase the forecast attachments for 2003 from 25,923 to 32,000. The Board will also increase the 2004 forecast from 27,015 to 29,785 attachments, the same number achieved by Union in 2002. The Board estimates that these changes will increase the fiscal 2004 rate base by $10.95 million. The actual amount will be reflected in the Rate Order.

Major Pipeline Facilities

Union's capital budget for transmission projects for fiscal 2004 is $25.176 million. Of this amount, $9.350 million is attributable to the IMP. Union has delayed its 18 km looping of the Dawn to Trafalgar transmission system between Brooke and Strathroy, to be completed for the winter of 2005-2006. Other transmission related projects to be completed in fiscal 2004 include the Guelph transmission system reinforcement ($3.127 million) and odourant facility upgrades ($1.5 million).

The Board finds the capital expenditures proposed for transmission related projects to be appropriate, subject to its findings that the allowed IMP expenditures be reduced to $8.15 million.

Storage Development Projects

Union is proposing to incur capital expenditures of $3.684 million on storage development projects, of which $2.0 million will be for gas chromatographs at all of its gas storage pools.

The Board rejects the position put forward by two intervenors that only half of the gas chromatographs expenditures should be incurred in 2004. As Union observed, it cannot balance its gas storage volumes if only half the pools are monitored.

The Board therefore approves the proposed capital expenditure of $3.684 million.

Pipeline Integrity Management Program

The Board is concerned at the escalating expenditures that Union claims are required to meet the TSSA requirements. In particular, total capital expenditures for 2004 were revised and increased from $8.51 million to $9.35 million and O&M expenditures increased from $5.57 million to $6.52 million. In addition, Union is requesting the recovery in rates of a forecast deferral account balance of $3.358 million, which results from expenditures above the Board approved level of $3.0 million for capital and $1.1 million for O&M costs, included in the PBR period for fiscal 2002 and 2003.

With regard to the ten year program to fully implement the IMP, estimated to cost $150.0 million, the Board did not receive any evidence to suggest that such expenditures were excessive to meet the requirements of Ontario Regulation 210/01.

Several parties suggested that an independent audit of the IMP costs be undertaken. The Board sees no necessity for such an audit. Other capital expenditures which routinely exceed the amounts being forecast for the IMP are not subject to an independent audit. The Board's hearing process is the forum in which the prudence of such expenditures should be established.

The Board is concerned at the rate of increase in both the capital and O&M expenditures that Union proposed to incur and recover from ratepayers in 2004. The Board accordingly directs Union to reduce the capital expenditures to $8.15 million and to $5.57 million for O&M, as originally filed.

The Board deems that safety and the reliability of the pipelines to be of paramount importance. The Board rejects the argument that the IMP implementation program should be extended from 10 to 20 years.

The Board will allow the disposition of the balance of $3.358 million in the IMP deferral account (account 179-Y1) as of December 31, 2003, subject to true-up of this balance. Deferral account 179-Y1 shall then be closed. There may be merit in establishing a variance account to record over or under-spending of the forecast O&M costs, as argued by IGUA. The Board would like to receive further evidence and submissions on this proposal in Union's next rates application.

Parkway Commitment

No submissions were received from parties on this topic. The Board will approve the methodology proposed by Union, but will require Union to provide updated information on its call provisions for 2005 in its next rates application.

Rate Rider Functionality

The Board does not agree with the position advanced by several intervenors that Union should be required to undertake market surveys to ascertain the views of ratepayers before improving its billing system. It is clear that Union's amended QRAM methodology, which the Board has reviewed in this decision, will require the transparent identification of rate riders, both positive and negative, to prospectively clear the forecast deferral account balances or to reflect rate retroactivity where appropriate.

Union's amended evidence indicated that the provision of rate rider functionality would require a doubling of the billing data to be stored. Also, the existing system architecture relies upon Oracle as the programming language. An enhanced version of Oracle will be required which involves a further licensing fee of $130,000.

The Board does not find the cost of $3.8 million to be excessive or unreasonable. However it is mindful that several of Union's software development projects have exceeded budget. The Board is not prepared to have ratepayers underwrite cost overruns on this project, should Union find that more resources are required to provide both the database capacity and the processing speed required. The Board expects that Union will enter into an appropriate contract with ADS to ensure that the work will be completed on schedule, and within budget. Further, Union is expected to apply appropriate project management controls to ensure that a cost overrun is not incurred.

The Board will not allow Union to recover the full cost of the project in rates for 2004. The Board accepts the recommendation of intervenors that the cost be amortized over a three year period. Therefore Union is authorized to include one-third of the estimated cost in the O&M budget for 2004. Union is directed to report on the status of the project in its fiscal 2005 rates application, to support recovery of the balance of outstanding costs.

7. CAPITAL STRUCTURE AND RATE OF RETURN

Union's Request

Union is requesting that the Board approve its proposed capital structure and capital costs.

Background

Union stated that its evidence in this proceeding is recommending a capital structure consisting of the following components: (1) 35% common equity; (2) 3.5% preferred equity, and (3) 61.5% of long and short term debt.

Union's proposed return on common equity is 11.625%, which is consistent with its evidence in the rate of return on common equity ("ROE") proceeding (RP-2002-0158). Union's proposed rate of return is based on a 5.625% risk premium and a 6.0% long Canada bond rate. Union stated that the evidence contained in the present filing, along with the expert evidence of Ms. McShane filed in the ROE proceeding, supported its proposal. Union acknowledged that the Board's decision concerning the ROE formula would be made in the ROE proceeding.

Union noted that the placement of debentures and preference share issues and the management of commercial paper for Union is now performed by the Duke Energy treasury department and stated this arrangement is similar to the previous arrangement between Union and Westcoast Energy's treasury department.

Union noted that the approved EBRO 499 utility capital structure consisted of short-term debt comprising 0.6%, long-term debt comprising 60.5%, preferred equity of 3.9%, and common equity comprising 35%.

Union stated that it was not proposing any changes to the EBRO 499 prescribed capital structure of 65% debt and 35% common equity, but only shifts in the weighting of the debt component, which consists of long-term debt, short-term debt and preference shares. In this context, Union stated that its proposed capital structure consisted of 35% common equity, 3.58% preferred shares, 65.69% long-term debt and negative 4.28% of short-term debt, reflecting a positive average cash position of about $131 million for 2004. Union argued that this capital structure, including the long-term debt and the cash position, would, on the evidence, provide sufficient financing flexibility in 2004 to manage the impact of warm weather and increasing gas prices.

Union stated that where cost of capital was concerned, it was proposing a cost of long-term debt of 8.45%, a cost of preferred shares of 5.44% and a cost of unfunded short-term debt of 4.15%. Regarding ROE, Union proposed that the Board approve an allowed rate of return based on the Board's findings in the generic ROE proceeding, as discussed above. Union also proposed that the Board use the most current consensus forecast of long-Canada's available at the time the decision is issued.

Union further stated that the average embedded cost of its preferred share capital for the 2004 test year is anticipated to be 5.44%, representing an increase from the 1999 Board approved level of 5.06%. Union stated that this was attributable to the decreasing income tax rate applicable to the allowable deduction affecting the tax on Union's preference shares.

Union provided its present ratings by Standard & Poor's ("S&P") and the Dominion Bond Rating Service ("DBRS"). S&P rated Union's Commercial Paper at A-1 (low), its Debentures at A- and its Preference shares at P-2 (mid). For DBRS, the corresponding ratings were R-1 (low), A, and Pfd-2.

Union stated that it considered it prudent to plan for an "A" rating to provide a safety net in the event of a ratings downgrade and to ensure that Union achieves the lowest risk adjusted cost of debt. Union stated that this conclusion was not based on any studies, but instead on the understanding that a higher credit rating is reflective of the rating agencies' assessment of a higher level of financial stability and lower risk level, with the lower the risk level, the lower the cost of borrowing.

Union stated that during the period 2000 to 2004, it anticipated issuing $635 million of additional long term debt, while redeeming only $382 million, and it was this increase in long-term debt which had significantly increased the weighting of long-term debt relative to short term debt in Union's proposed capital structure. Union attributed this shift to greater financial needs experienced by the Company in the period of 2000 to 2004 due to reduced short-term credit lines, high gas costs, and the need to carry customer deferrals for an extended period of time while awaiting the issuance of the RP-1999-0017 and RP-2001-0029 decisions.

Union noted that preference shares had decreased as a percentage of rate base due to an increase in the rate base with no proportionate growth in the preference shares.

Union advised that it has a Medium Term Note ("MTN") program that allows it to issue debentures with terms ranging from two to thirty years. Union stated that the MTN program allows for the issuance of debt in smaller increments and on a more frequent basis to better meet its financing needs, while also providing for terms that are most attractive at the time of issuance. Union summarized the MTN program advantages as being that the program allowed for lower debt cost, more frequent renewal of debt in general, greater flexibility in determining the debt's term and greater flexibility to minimize Union's embedded cost of long-term debt.

Union stated that it had recently completed the issuance of $200 million of debt under the MTN program, having a five-year term and a 5.19% coupon rate. Union added that its forecast reflected no further issuance of debt through 2004. Union also noted that it regularly reviewed opportunities to redeem its long-term debt in an effort to lower its overall embedded debt cost. Union stated that its combination of redemptions and new issues had decreased its embedded debt cost to a forecast 8.45% in 2004, from the 1999 Board approved cost of 9.61%.

Union noted that some questions had been raised during the hearing about the net average cash position, with the suggestion being made that an average net cash position is somehow inappropriate and would imply that the level of debt issued by Union in 2002 was too large. Union submitted this was not the case and that unfunded short-term debt, or cash position, was simply reflective of the seasonal cash flow of the business. Union's monthly cash position for the years 2002 to 2004, showed that Union was in a cash position during the summer and shoulder months and then drawing on lines of credit in the winter to the extent of $197 million by December 2004, leaving $168 million to deal with unforeseen circumstances.

Union stated that it was important to note that it could not issue debt effectively in small amounts, and it was therefore necessary to wait until capital needs were such that there was sufficient justification for long-term debt financing. However, this did not preclude the possibility of taking advantage of favourable market conditions at a given point in time.

Union also noted that in 2002, at the time it had undertaken the financing, it was carrying a high level of deferred receivables, which was one of the factors that had caused it to issue the debt. However, at the present time this was not forecast to be a significant problem.

Positions of the Parties

A number of Intervenors expressed concerns about Union's unfunded short term debt level. The argument was made that due to the perceived prefinancing of Union's most recent long term debt issue, ratepayers were being charged 8.5 % on the long term debt component of the capital structure, while only receiving a credit of 4.15% on the pre-funded component. This, it was argued, inappropriately burdened ratepayers with an added cost of $5.6 million. A variety of ways of dealing with this perceived inequity were proposed.

IGUA also expressed concern that Union's actual equity ratio, which was, as of December 31 for 2002, 2003, and 2004 respectively 31%, 32.4% and 30%, had fallen considerably below the 35% deemed common equity level which the Board applies in deriving rates. IGUA took the view that if this situation was to persist, Union's equity ratio for rate-setting purposes should be reduced.

LPMA/WGSPG and VECC argued that where Union's common equity ratio and risk was concerned, the changes in the monthly fixed charges proposed by Union in this proceeding and the increases that took place under PBR, along with weather hedges, are more than significant enough to warrant a review of the company's business and forecast risk.

LPMA/WGSPG and VECC therefore submitted that consideration of both these issues should be delayed until the 2005 proceeding at which time both intervenors and Union could bring forward evidence/experts to deal with any changes in business risk associated with these matters.

Union's Position

Referring to the level of long term debt, Union noted that it could not cost-effectively raise debt in the market in small tranches. Union noted that debt issues were necessarily lumpy in their impact on capital structure. Union also argued that intervenors who were questioning its long-term debt levels were ignoring the fact that even with the level of long-term debt Union had issued, it still found it necessary to draw substantially on its short term credit facilities during the course of the year, and, in the absence of the long-term debt issue, would have exceeded its short term borrowing capability in 2004. Union's forecast maximum short-term indebtedness would have reached $397 million, exceeding the 2004 capacity of $365 million.

Union further explained that the average cash position in the short-term unfunded debt component of the capital structure arose principally because the level of deferred charges carried by the Company are anticipated to be significantly lower in 2004 than they had been in the past because of the new prospective recovery mechanism approved by the Board for Union beginning in May 2003. Union stated that at the time it had issued its long-term debt in 2002, it could not have been known that the new mechanism would become standard practice, and, as such, Union's level of long-term debt should not be considered to be inappropriate.

Union submitted that there was no evidence that it had in any way been imprudent in raising its 2002 debt. Union stated that it had an opportunity to raise debt capital at favourable rates and had appropriately taken advantage of it.

Union argued that IGUA's submission that its approved equity should be reduced to reflect historic equity ratio levels for 2002, 2003 and 2004 should be rejected on the basis that IGUA's calculations were both computationally and conceptually incorrect. According to Union, the IGUA calculations understated the true equity ratios by 3% to 5%.

Board Findings

The Board issued its Decision in RP-2002-0158 on January 16, 2004. In that Decision the Board rejected the proposal made by Union and EGDI respecting changes to the formula used to establish ROE. Accordingly, the rate of return on common equity applicable to the revenue requirement established in this case is based upon the existing ROE Guidelines. As of December 2003, the long term Government of Canada bond yield was 6.00 %. The Board finds that the corresponding ROE for Union shall be 9.62% The new rate schedules arising from this Decision will reflect this ROE.

The Board finds that Union is in compliance with its deemed capital structure. Union's evidence revealed that with respect to long-term debt it had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance. Insofar as the variance was marginal, the Board considers this practice to be acceptable. If taken to more significant levels, this approach to the debt side of the capital structure equation could become problematic in certain market conditions. The Board considers that utility management should be in a position where it can conduct the business confidently and conventionally, without fear that the regulator will intrude to second guess decisions which are reasonable at the time they are made. Such divergences as have been highlighted in the evidence with respect to aspects of the capital structure are not of a magnitude so as to require Board intervention.

The Board accepts the proposed capital structure of 35.0% common equity, 3.5% preferred equity and 61.5 % long and short term debt for 2004.

Throughout the proceeding intervenors raised issues respecting the adjustment of Union's risk premium as it affects its approved return on common equity. The risk premium element of the return on equity formula is designed to reflect the extent to which the utility is exposed to genuine business risk. Intervenors suggested that changes in weather methodology, the adoption of hedge strategies related to weather, and the increase in monthly fixed charges ought to be reflected in a reduced risk premium. This would have the effect of reducing Union's overall approved return on common equity. The Board applies the ROE formula to the revenue requirement established for the utility. Parties are free to submit evidence respecting the accuracy of the risk premium in subsequent proceedings.

8. LOAD BALANCING AND MARCH PARK

8.1 LOAD BALANCING

Background

The current method of Load Balancing has been in place since the inception of the Bundled-T service some 15 years ago.

Load Balancing service, that is the timely matching of system supply and demand, is required when the amount of gas delivered by customers varies from the amount they physically consume on a given day or throughout the season. Union's Board approved methodology for recovering load balancing costs, and its proposal in this proceeding, arise from Board directives in previous decisions.

In its EBRO 494 Decision, the Board directed Union "... to conduct a cost allocation study and propose a rate structure similar to that of Centra where the forecast cost of short-term supplies are included in the delivery charge. In that way all customers, such as ABC customers who cause load balancing costs to be incurred will pay those costs."

In the EBRO 493-04/494-06 proceedings, Union proposed to classify all costs in the Other Purchased Gas Cost Account in excess of the Ontario landed WACOG as either load balancing or flexibility costs. Both of these costs would be recovered in delivery rates by rate class. Regardless of whether customers in a rate class were sales service, buy-sell service, or bundled-T service customers, all would pay the same charge, under the rationale that incremental supplies purchased in the winter to meet actual winter demand benefitted both direct purchase and sales service customers.

In its EBRO 493-04/494-06 Decision, the Board accepted Union's proposal but went on to suggest that a possible alternative might be to incorporate these features:

1. a monthly supply/demand inventory forecast for each type of service;
2. calculation of monthly differences between supply and demand;
3. comparison of monthly actuals to forecasted amounts; and
4. a true-up mechanism.

In its EBRO 499 Decision, the Board found that the existing load balancing cost methodology should be continued for the 1999 test year but that as soon as Union completed its unbundling exercise, the Board expected Union to bring forward a new load balancing proposal.

Union uses storage space and deliverability, balancing gas inventory, and spot gas to provide load balancing services. The recovery of the load balancing costs associated with each asset type is accomplished according to the type of asset used. Storage space and deliverability costs are recovered in delivery rates based on the forecast use of these assets by each rate class. Costs of the balancing gas inventory, which comprises 29.5 PJ, are allocated to all rate classes, which is similar to the treatment of Union's working inventory. Costs of incremental or unplanned spot gas supplies, which are used to balance sales service and Bundled-T customers when actual winter demands exceed forecast demands, are recovered from these customers. The costs of load balancing using spot gas are calculated by multiplying the volumes of spot gas purchased in winter to meet unplanned demand by the summer/winter price differential.

Union's Position

At present, Bundled-T customers must supply their daily contract quantity ("DCQ"), a quantity based on each customer's normalized consumption over the most recent 12 months for heat-sensitive loads. The cumulative variance between supply and demand is recorded in each customer's Banked Gas Account ("BGA"). Each customer's BGA must be balanced within 4% (+/-) of zero annually, at contract year end, to avoid failure-to-balance charges. Although customers may supply incremental gas when actual consumption exceeds forecast (e.g., in the winter), most Bundled-T customers do not choose this option. As a result, Union must purchase incremental winter spot gas to maintain system integrity and storage deliverability. Union allocates the costs of this delivered supply, calculated as the product of the winter-summer price differential and the volume of incremental spot gas, to all customers at the rate class level in proportion to the difference between each class' forecast and actual imbalance on March 31. Union added that incremental winter spot purchases could result in Union incurring summer UDC if the winter spot volumes exceeded summer spot requirements.

Union identified several issues raised by its current practice. Bundled-T direct purchasers do not understand that their gas suppliers have arranged for Union to provide load balancing services and hence they do not understand why they are charged for gas costs by Union. Further, the allocation of load balancing costs to all customers by rate class, regardless of whether individual Bundled-T customers in the class are balanced seems problematic. There is potential to create UDC for Union due to Bundled-T summer incremental balancing supplies displacing Union's planned summer sales gas purchases. Additionally, the current practice increases Union's exposure to the volatile spot gas market in March for balancing sales service and Bundled-T customers.

Union proposed that Bundled-T (Southern) customers be required to balance to their forecast BGA balancing checkpoint on February 28 if consumption is greater than forecast; and also to shed any surplus gas by September 30 if consumption is less than forecast. The obligation to balance is subject to a 10 GJ per contract tolerance.

Union asserted that under its load balancing proposal, in conjunction with its March Park proposal, it would only have to buy winter spot gas for sales service and Northern direct purchase customers. It would still be able to ensure sufficient deliverability and gas in storage in the winter and could also ensure that sufficient fall storage is available to meet both the firm injection rights of its customers and storage availability by the end of September to meet winter requirements.

In response to IGUA’s desire for a transition period for the implementation of the new load balancing methodology, Union stated that the operation of the program would be straight forward and direct. Customers would be informed in early February of the amount that needed to be delivered by February 28, and any residual imbalances would be addressed by Union to the account of the customer. There would be no need to ‘phase-in’ the proposal.

Union dismissed IGUA’s argument with respect to Transactional Services revenue. Union stated that insofar as the transactional fee would only be 0.3 cents/GJ, the additional revenue would not likely be significant and would be shared 75/25 in favour of the ratepayers.

In response to OES’s and Schools’ suggestion that Union’s sales service customers ought to be subject to a trueing up and balancing exercise resulting in some circumstances in additional costs, Union noted that there were significant differences between the contract direct purchase market and the sales service environment. In particular, Union stated that unlike the contract direct purchase market, the forecast volumes for sales service were weather-normalized, reducing the likelihood of material imbalance. In addition, Union noted that unlike contract direct purchasers, sales service customers are not metered on a daily basis.

In response to OES’s and other marketers’ concerns, Union noted that it had engaged the marketers in discussions respecting the development of appropriate forecasts and forecast methodology. Union also claimed that if it allowed marketers to determine their supply requirements, the result would “corrupt” Union’s planning. Union is not able to accommodate different forecasting methodologies at the same time.

In response to marketers’ requests for the right to diversion between themselves, Union stated that such an approach would conflict with the principle that load balancing should be managed on a customer-specific basis.

Intervenors' Position

Several Intervenors supported Union's proposal.

IGUA asserted that because of the increased number of title transfers to accommodate the new methodology Union would experience windfall revenue.

OES and Schools suggested that Union should impose the same balancing requirements for the sales service customers. OES further submitted that Union did not negotiate forecast volumes with the marketers and that the marketers should have the right to diversion among themselves.

Intervenors were concerned that the balancing tolerance was too constraining and the penalty-based imbalance charge was not appropriate.

VECC did not support Union's proposal as direct purchase customers will be able to draft the system on a day-to-day basis and that there were other services that the direct purchase customer can use to avoid Union purchasing balance gas on their behalf.

Board Findings

Under the current practice, Union accounts for and provides for shortfalls and surpluses in the gas accounts of direct purchase customers. All of the costs associated with procuring spot gas for direct purchase customers overusing in the winter period and the costs associated with the shedding of surplus gas in the Fall, have previously been allocated to the rate class to which the imbalanced direct purchase customers belong. This has the effect of burdening all members of the class with increased costs, whether or not they had operated within their contractual obligations and forecasts. This violates the principle that those who cause costs ought to bear them. The notable virtue of the Applicant's proposal is that it places the responsibility for balancing costs with the direct purchase customers.

The proposal is also consistent with the Direct Purchase customers acting as managers of their respective gas supply requirements. It is appropriate and equitable for them to have an enhanced and better informed opportunity to track and manage their position at the two critical periods in the year. To date they have been dependent on the Utility for the management of divergences from forecast. Having chosen Direct Purchase gas supply, it is predictable that direct purchasers would prefer an informed opportunity to manage any divergences from forecast that have arisen at February and September.

Finally, the Board considers the proposal to be an enhancement of security of supply for the system as a whole. While the Board approves the Applicant's proposal with respect to load balancing, there are some important transitional issues which must be addressed.

First, the evidence was clear that implementation of the proposal would have the desirable effect of changing the allocation of load balancing costs. Currently, costs related to balancing the system are imposed on all in-franchise customers without regard to their respective out-of-balance status. The adoption of the proposal places responsibility for over-and-under supply where it belongs, on those direct purchase customers who are out of balance at the stipulated Winter and Fall checkpoints.

In order to enable the direct purchasers to plan for and accommodate this significant change in their exposure, Union has communicated the import and potential implications to those most likely to be directly effected. However, this change is particularly problematic for the gas retailer who has entered into fixed price contracts with consumers. Where such contracts strictly prohibit mid-term changes in the contract price of gas, the marketers are faced with the prospect of having to absorb any increased costs associated with trueing up their respective balance positions at the checkpoints. This outcome represents an unintended and undesirable side effect of the implementation of the Applicant's otherwise desirable proposal.

The position is complicated because the gas retailer typically has no input into the initial establishment of the forecast, for which it is now to be solely accountable. Under current practice, Union does not appear to accept input from the retail gas marketer, and bases the forecast on the last year's actual volumes, which are then weather normalized. No other input informs the forecast. If the retail marketer is to now to bear the burden of maintaining balance, it must have a reasonable opportunity to provide input into the establishment of the forecast.

The establishment of an annual forecast that is developed as a consensus between the Utility and the Direct Purchaser, extends to all direct purchase customers. Parties to this proceeding raised serious concerns respecting the extent to which their input into the development of the forecast was considered. Kitchener, for example, believes that the forecast developed for its needs understates its genuine requirement. OPG also contends that the load forecasting process does not adequately take its input into account. Where direct purchasers are to be directly accountable twice a year for imbalances in their respective gas supply accounts, the forecasts should be the result of a consensus between the customer and Union, each acting reasonably.

The forecasting process should not become a strategic exercise. Customers who attempt to artificially inflate their forecasts in order to develop ancillary trading opportunities should not expect Union to accommodate this narrow interest. The Board is prepared to address situations where either the Utility or the direct purchaser is not approaching the establishment of the forecast in a reasonable or fair way. The Board expects that in such circumstances one party or the other would initially raise the issue with the Board. The Board may refer the issue to Board staff for mediation and review. If that is not successful in resolving the issue, the Board itself may intervene.

The refinement of the load balancing activity, and the imposition of more direct accountability for direct purchase customers also leads to a consideration as to why the Utility ought not to be required to develop forecasts for its system customers, in the same way that direct purchasers are required to commit to volumes for their use. Excluding the system customers from responsibility for under-or-over use of gas reserves has the effect of insulating them, from a financial point of view, from such effects. This has the undesirable effect of imposing on the retail customer of a gas marketer a category of cost to which the system customer is not subject. On its face, this seems to be an unreasonable obstacle in the development of the gas retailing market.

The Board will not require Union to operate to a forecast for system customers at this time. The Board directs Union to come forward with a proposal at the time of its next rates application addressing this apparent anomaly.

8.2 MARCH PARK

Union proposed to include in rates the costs associated with protecting against under forecast demand variances due to late season colder than normal weather. This was to be achieved by 'parking' borrowed gas in March for repayment the following May. A park is a gas supply instrument whereby molecules are borrowed from a third party pursuant to a contract and then returned to the party at a later time. This would eliminate the need for Union to buy spot gas in March for either sales service customers or Bundled-T customers at a time when prices are most volatile.

Union examined the variations between actual and forecast consumption over the past 4 years for the month of March and found that the average was 6.5 PJ. Union further applied a diversity factor of 80% to arrive at the March Park requirement of 5.2 PJ.

The cost claimed by Union is based on the price difference between the prevailing price in the month when the gas was borrowed and the prevailing price in the month when it is returned. The average price difference between these points in 2003 was $1.60/GJ. Therefore, Union proposed to recover $8.4 million within the proposed 2004 rates.

Union's Position

Union claimed that taken together its new load balancing provisions and the March Park proposal would result in the following benefits:

1. An individual customer would be responsible for its own costs if its consumption differed from the forecast;

2. Union would provide balancing services for bundled service to a planned or forecast level;

3. Union would not have to purchase spot gas for Southern Operations area Bundled-T customers by including the March Park in delivery rates.

4. Union would also eliminate retroactive adjustments for Bundled-T customers, while Southern Operations area Bundled-T customers could have some flexibility in balancing;

5. Union would continue to purchase spot gas to load balance Northern and Eastern Operations area Bundled-T direct purchase and sales service customers for the winter up to February 28. The March Park would eliminate March spot purchases and the deferral recovery adjustment related to spot gas would be reduced;

6. Union could manage variances in the early winter season by purchasing spot gas using monthly pricing. However, any volume variance in the month of March would have to be reconciled by March 31 resulting in the need to go to day pricing;

7. Simplified administration, since action would only be required in one direction at each checkpoint;

8. Union could plan and manage its portfolio based on aggregated forecast demands and supplies on its system;

9. Union would be able to provide customers with more diversion;

10. The volatile spot price risk in March would be removed for all sales service and Bundled-T customers.

Union reiterated that the March Park was a method of avoiding retroactive gas cost charges and, as such, was an important component of the load balancing proposal.

In response to the proposal to use March 31 as another balancing checkpoint, Union stated that it was unsafe to wait until the last vestiges of winter, at the end of March, to determine if direct purchase customers would be in balance. Such an approach could compromise system integrity.

Union stated that the March Park was not a strategy to increase S&T Transaction Revenue. If there was excess capacity, it would be marketed as part of Union's S&T transactional business and would be deferred and revenues shared 75/25 in favour of the ratepayers.

Union agreed that the March Park would have potential to reduce interruption to interruptible customers. However, because the quantification of this benefit is difficult, it would be inappropriate to allocate any portion of the additional cost to interruptible rate classes.

Union stated that increased opportunities for diversion were not related to the March Park proposal but rather were dependent upon warm weather and the resultant availability of excess capacity.

Union indicated that it would amend its bundled-T contracts with an expiry date of April 1, when requested to do so. Union rejected WGSPG's suggestion that M9 and M10 rate classes should be exempt from the March Park cost allocation since no rationale was given for this suggestion. Union stated that the March Park was designed to cover the requirements of all infranchise customers so M9 and M10 should bear their share.

Union currently has approximately $6 million of load balancing costs embedded in rates in 2004. The March Park cost of $8.4 million represented a proxy for potential load balancing costs to avoid a retroactive charge. Union submitted that the net difference in rates would be only $2.4 million with the inclusion of the March Park.

Intervenors' Position

Many intervenors supported the March Park in principle but did not support the recovery of $8.4 million in costs associated with the proposal for inclusion in 2004 rates, as users will not benefit until 2005.

Many intervenors were also not comfortable with the estimate of 5.2 PJ. The intervenors felt that the price differential was not as substantial as Union had suggested and as a result, the $8.4 million claim was excessive.

Some intervenors proposed to add March 31 as another balance point for the BGA.

Board Findings

The Board considers the March Park proposal to be inconsistent with the other load balancing elements of the application. The key element of the twice-a-year reconciliation of gas supply accounts for direct purchasers in the Applicant's load balancing proposal has the effect of placing the direct responsibility for deviations from forecast on the individual contracting parties. The March Park proposal calls for a system-wide allocation of the cost of this insurance measure, without regard to which customer has caused the need to procure additional supply during March.

The suggestion that this insurance measure avoids retroactive recoveries is not convincing. First, the provision of gas to the system within the period in which it is required is accommodated within the amended QRAM process in a reasonably timely manner. Second, the only approach to recovery for commodity purchases less palatable than retroactive recovery is an overly conservative and excessive prospective recovery, where the Utility has accumulated surpluses. In developing approaches to this kind of situation, the Board must find a reasonable balance between excessive recovery on a prospective basis and short-term retroactive charges.

The March Park proposal also creates concerns respecting the timing of the expenditure, and its inclusion in the revenue requirement for 2004, when the program would not be available until 2005. This very considerable lead time is inconsistent with the principle that costs should be incurred as close as possible to the period to which they relate. There seems to be little justification for the inclusion of $8.4 million in the revenue requirement for 2004.

Finally, there is an issue concerning the need for this insurance program. In the last five years, the program would only have been needed in the last year, that is, 2003. Given the very substantial expenditure involved, it seems that the March Park proposal is oversized, or may not be necessary at all except in extraordinary circumstances. Several parties suggested that a deferral account be established to account for circumstances in which the volumes provided for in the March Park facility were over- or under-target. These suggestions miss the point that the facility is an all or nothing measure, and the premium for the gas secured is payable without regard to the amount actually drawn pursuant to it.

Accordingly, the Board will not approve the March Park facility.

9. COST ALLOCATION AND RATE DESIGN

9.1 COST ALLOCATION

Background

This is the first integrated cost allocation study filed by Union since 1998. With some exceptions, the outcomes are generally consistent with approaches approved by the Board in prior rate cases. In most cases, the allocations mandated by the integrated study were not significantly different from previous allocations.

One change in the methodology used by Union in the integrated study concerned the pooling of plant and O&M costs for the Southern operations area with those of the Northern and Eastern operations area. Approximately one percent of costs in the Northern and Eastern operations area have been functionalized using allocation methods previously approved for the Southern operations area. Union continued to use the 'minimum plant' method to classify the cost in the Southern operations area and used the 'zero intercept' method to classify cost in the Northern and Eastern operations area . The "minimum plant" method classified customer costs based on the relationship of inch-diameter of distribution mains. In general, pipes that have a diameter of less than four inches were deemed to be customer related. The "zero intercept" concept classified customer costs based on the assumption that there is a linear relationship between the capital costs of the physical plant, as built, and the theoretical cost to sustain a zero consumption. Union also developed new allocation factors where needed to allocate the new costs items such as GDAR and Load Balancing Costs.

Intervenors took exception to some of the allocations proposed by Union. These areas of dispute are discussed in detail below, together with some allocation proposals which were not contested, but which are noteworthy. The study itself, in its entirety, can be viewed at the Board's Library.

Balancing Inventory

Union holds gas in inventory to balance the demands of both sales service and direct purchase customers in the Northern and Eastern operations area and the Southern operations area. For inventory revaluation purposes, gas in inventory for resale to sales service customers was tracked separately from inventory identified to balance sales service customers.

Union proposes to allocate balancing inventory to in-franchise bundled rates classes, excluding T-service, based on the excess of winter volumes (November - March) compared to average annual use for the same 151 day period. T-service customers were not allocated the costs associated with balancing inventory because, under the terms and conditions of their service, these customers are required to balance their own demand/supply needs. This approach to the allocation of these costs was not contested.

Board Findings

There were no submissions with respect to the allocation of these costs. The Board approves the Applicant's proposals.

Allocation of Distribution Capacity-Related Costs

Background

Union's treatment of this cost category was disputed by a number of Intervenors.

Union has proposed the application of the Northern and Eastern Operations area approved allocation method for the Southern Operations area, which is its current allocation methodology. In other words, it proposes to apply the same cost allocation methodology to the Southern operations area as is used for the Northern and Eastern operations area and to allocate distribution capacity-related costs in the Northern and Eastern Operations area using design day demand exclusive of the demands of customers served directly off of transmission lines, as it defines them. A key element in Union's allocation methodology is the functionalization of pipe as sole-use, joint use, or grid main use. Only those customers considered to be sole-use connections are allocated capacity related distribution costs. Another key element in Union's approach involves the characterization of high volume, high pressure pipe as transmission-related assets, and not distribution assets.

Union's Position

Union stated that even though the Southern operation areas operates on a more integrated basis, it was still possible to track those customers who do not cause Union to incur distribution capacity related costs. In the Northern and Eastern operation areas the demands of customers served entirely by sole use mains have been excluded from the allocation of grid and joint use mains, while in the Southern operation areas the demands of customers served off of transmission mains have been excluded from the distribution capacity allocation.

Union also stated that it has clearly shown in Ex. N20.2 which lines were classified as transmission or distribution based on Board's Uniform System of Accounts.

Union submitted that the intervenors misunderstood the Board's direction in E.B.R.O. 499. In that case the Board had required Union to develop a new methodology for the allocation of costs which recognized the differences in the respective operational areas. Union submitted that the Board approved Union's proposed rates in that case, which incorporated the change in allocation. Union has allowed the revenue to cost ratio to adjust to reflect the disallowance of the change in allocation. The current proposal was to allow the cost allocation study to "catch up" to the Board's approved rate design in E.B.R.O. 499.

Union submitted that it had provided new evidence in this application showing the integration of the cost allocation method, and providing a comparison between the two methodologies.

Intervenors' Position

A number of Intervenors objected to Union's proposal, suggesting that it does not vary from the cost allocation methodology presented by Union in E.B.R.O. 493/494 in March 1997 and E.B.R.O. 499. This is the same methodology which was rejected by the Board in both of those cases, and which lead to the Board's direction in E.B.R.O. 499, referred to above. They also suggested that the underlying inadequacy of Union's methodology remains: large customers are under-allocated capacity-related distribution costs at the expense of other rate classes.

At the core of the Intervenors objection is the suggestion that the use of an allocation methodology suited to the Northern and Eastern operations for Southern cost allocations ignores the fundamental differences in the respective delivery systems for each operations area. In the North, distribution to customers is typified by high volume, high pressure spurs running from the TCPL transcontinental pipeline to customer's installations. In the South the system is much more integrated, with a sharper distinction between distribution infrastructure and transmission assets.

VECC argued that Union's methodology had serious implications for future cost allocations. For example, if downstream demand grew significantly, existing distribution infrastructure could be replaced with high volume, high pressure pipe. By Union's logic, VECC suggested, distribution customers would become transmission customers, and they would be excused their former share of capacity-related distribution costs, to the prejudice of other distribution customers.

VECC noted that the impact of Union's proposal would be to shift $12.898 million in costs from contract customers to the M2 rate class.

VECC argued that because the Southern Delivery Area is an integrated system, any attempt to allocate distribution capacity costs in the South consistent with the allocation in the Northern and Eastern Delivery area would allocate overall system costs inequitably. VECC urged the Board to reject Union’s "recycled and twice-disallowed" proposal and again direct Union to align rates with the approved cost allocation design, holding Union itself responsible for any costs shifted to the general service class as a result of non-compliance.

Schools noted the Board’s response to Union’s proposal in the EBRO 499 Decision:

> The Board is unconvinced that there are not underlying fundamental differences between the configuration of the infrastructure serving customers in Union’s Southern and Northern and Eastern operations areas, particularly the Northern area. In the Board’s view Union’s attempt at harmonization using only the cost allocation step is incomplete. (3.1.28)
>
> In particular, Union has not satisfied the Board that separation of transmission and distribution service is identical for the two service areas. In the Board’s view a complete approach to harmonization would first involve functionalization of Southern operations area pipe costs as either grid, joint or sole use main (or conversely to re-functionalize Northern operations area costs), followed by classification as capacity or commodity related costs. The Company’s own witness indicated that the proposed cost allocation change was in the right direction but stated "when we [have] completed our analysis as far as integrating cost allocation methodologies that will be something that we look at and evaluate whether we can do it". (3.1.29)

Schools opposed Union’s proposal for essentially the same reasons, as expressed by VECC.

Schools submitted that distribution mains in the north were functionalized as either joint use, grid, or sole use, with the last classification representing only 7% of total mains costs in rate base. Schools argued that where grid use mains have larger customers connected to a larger mains and smaller customers attached to smaller mains, a larger customer shares in the costs of downstream or upstream mains, the rationale being "... whether it was attached before or after the downstream or upstream grid customers, it benefits from their sharing of the costs of the larger main in the grid. However, in the South, many of the transmission lines have grids mains attached and large customers therefore will not have to pay the full costs of the transmission mains as they would have to pay for sole use mains in the North. For this reason, Schools argued that Union’s arguments that its proposal was consistent in both areas were flawed.

Schools noted that M7, a beneficiary of Union’s proposal, is now at a revenue-to-cost ratio of 0.95, "testing the limits of acceptable ratemaking."

Schools concluded by urging the Board to reject Union’s proposal and to direct Union to adjust its rates accordingly. Schools argued that Union had not provided any new evidence, other than a flawed analogy to functionalization of sole use mains in the North, in support of its third attempt to get approval for its "identical" proposal.

IGUA supported Union’s proposal, noting that large volume customers were dealing with the burden of the DCC elimination and should not be responsible for $14.74M in distribution capacity costs caused by other classes.

IGUA also argued that acceptance of Union’s proposal was necessary to respect the principle of cost causality.

Board Findings

The Board considers Union’s proposal in this case to suffer from the same disability highlighted by previous panels: the operational differences between the Southern and the Northern and Eastern operations areas are material, and require different cost allocation methodologies in order to be equitable. In its EBRO 499 Decision, the Board stated:

> The Board rejected an identical proposal in its decision in E.B.R.O. 493/494 on the grounds that, to the extent that a rate class is predominantly served through transmission capacity, the proposal could result in inappropriate level of avoidance of distribution capacity costs.

The Board accepts Union's methodology for the purposes of establishing rates for 2004. The Board directs Union to develop a more appropriate methodology to be incorporated into its cost allocation study to be presented for application in the next rate case.

System Integrity Costs

Union's Position

Union submitted that the issue raised by Intervenors was also raised in RP-1999-0017. Union observed that in that case the Board found that ".. System integrity is required to manage weather-related variances for customers regardless of whether they take bundled or unbundled services. The Board accepts the cost allocation results ... and accepts Union's proposal for the allocation of these storage costs." Union argues that the same factors apply today as applied then. In its view, it is appropriate to allocate the costs related to the quantity of gas used to support system integrity to weather-normalized rate classes. The gas so designated is designed to support the system when weather conditions stretch its capability to meet system demands.

Intervenors' Position

VECC submitted that allocating these costs solely to the general service customers (M2, R01 and R10) was inappropriate insofar as all customers of the utility benefit from the maintenance of the system as a whole. It suggested that the cost of the contingency space should be allocated to all customer classes.

Board Findings

The Board confirms its approval first given in RP-1999-0017 with respect to the costs associated with Union's system integrity practice. In the Board's view, the allocation of these costs to customer classes whose consumption is more directly related to weather variation is appropriate.

Cost Allocation to Rate R25 - FT Transportation Demand, FT Transportation Commodity and FT Transportation Fuel

Union's Position

Union states that it acquires firm capacity in the North in order to meet peak day demands. The allocation of firm gas supply transportation charges to R25 was based solely on winter demand. Union stated that in winter, if there are no interruptions, R25 customers are using the exactly the same facilities as firm service customers. Accordingly, in its view, it is equitable that R25 be allocated a portion of such costs.

Union submitted that the allocation methodology was consistent with the Board's E.B.R.O. 484 (Centra Gas 1994 Rates) Decisions with Reasons.

Intervenor's Position

OPG submitted that rate classes were distinguished on the basis of load, load factor and quality of service. Quality of service distinguishes between customers receiving firm service, and interruptible service. Interruptible service, by virtue of being interruptible is a lower quality of service. Allocation of costs must reflect the different levels of service being provided to different rate classes.

OPG submitted that R25 Interruptible, the lower quality of interruptible service, has been inappropriately allocated FT transportation commodity, fuel and demand costs which were costs incurred in relation to the provision of firm service. This would be inconsistent with the finding of the Board in E.B.R.O. 499 that "Union does not contract for firm transportation capacity specifically to serve Rate 25 or other interruptible demands."

Board Findings

The Board approves Union's current allocation to the R25 rate class. The Board recognizes that interruptible service is an inferior service and that this aspect must be reflected in the overall rate treatment for such customers. That is why interruptible customers pay lower base rates than customers who require firm service. The Board also notes that interruptible customers are not allocated costs related to base load capacity. Base load capacity is exclusively allocated to the firm rate classes. It would not be appropriate for the interruptible class to escape all allocation related to capacity since they are being served by the same assets as all other customers.

The Board also notes that the market place has evolved with a model of interruptible service which results in very infrequent interruptions of service. Many market participants have organized their affairs according to this market model. To accept the intervenors' position on cost allocation for this class could have the effect of changing the underlying assumptions and expectations which have become associated with this service choice. Accordingly, in the Board's view, Union's current methodology is appropriate.

Advertising

Union's Position

In E.B.R.0. 499 the Board directed Union to "... address the different approach used to classify advertising costs for the Northern and Eastern Operations area as part of its rate harmonization initiative." At the time, customer-related amounts were allocated to rate classes in both service areas in proportion to the weighted average number of customers in that service area. Commodity-related amounts were allocated to Southern rate classes in proportion to delivery volumes for in-franchise customers.

Union proposed that customer-related advertising costs be allocated to rate classes in proportion to the weighted average number of customers and commodity-related amounts be allocated to rate classes in proportion to delivery volumes for in-franchise customers.

Union proposed that demand-related amounts be allocated to rate classes in proportion to the peak day demand of firm and interruptible customers served by the distribution system, excluding customers served directly off transmission lines.

Union proposed to allocate customer-related amounts to rate classes in proportion to the allocation of other distribution sales promotion costs. There were some customer-related sales promotion supervision costs directly assigned to the T3 and M9 rate classes. This allocation was justified, in Union's view, in recognition of the generic benefit provided to T3 and M9 customers resulting from Union's natural gas promotion.

Union observed that Kitchener has objected to being allocated a portion of the sales promotion costs in the past while Kitchener was a M9 customer. In E.B.R.O. 493/494 the Board concluded that Kitchener should expect to receive a share of sales promotion costs. Union stated that the same argument is still valid today.

Union submitted that the Kitchener service territory was surrounded by Union's franchise area, and that Kitchener will benefit from Union' s advertising and promotion activities. Accordingly, it was fair to allocate some costs to Kitchener.

Union stated that the allocation of sales promotion supervision costs was based on actual time spent by a particular sales manager serving four M10 customers and eight M7 customers. As such, the allocation was fair and appropriate.

Union accepted that it may not be valid to include M10 among major market customers, but given the amount involved and the basis of allocation, Union requested the Board to accept the allocation.

Intervenors' Position

Kitchener submitted that it does its own advertising, and that Union's advertising was duplicative. OPG was concerned that $672,000 of advertising costs was being allocated to eight customers in M7. WGSPG was concerned that the M7 rate class, with eight customers was allocated merely $19,697 of sales promotion supervision costs, whereas rate class M10, with four customers, was allocated $15,767.

Board Findings

The operation of a fully integrated natural gas distribution system creates a complex matrix of interdependence between customers and the system manager. The growth of the system, the proper maintenance of the system, and virtually every other element of its operation creates impacts for all system participants. In this context, the costs incurred by the system manager to expand usage and to communicate important system messages and values through advertising and other communication tools enures to the benefit of all system participants. The Board sees no extravagance or imprudence in the utility's costs in this area, nor in its method of allocation. The Board therefore approves the Applicant's proposal.

Hearing Costs

Kitchener submitted that, since Kitchener does not claim intervenor's costs, no hearing costs should be allocated to it.

Union's Position

Union submitted that the hearing process impacts all rate classes. Even though Kitchener was not claiming intervenor costs, Kitchener participated in the ADR process, as well as the hearing, and filed extensive written argument. This participation contributed to higher costs for the whole process. In Union's view, it would be unfair for Kitchener to be exempt from a portion of the hearing costs.

Board Findings

The hearing process is an integral part of regulating a monopoly service provider and the costs associated with this process therefore should reasonably be expected to be borne by ratepayers. Intervenors have full opportunity to cross-examine, lead evidence, and make arguments to the Board with respect to any aspect of the Applicant' s proposals, whether or not they make a claim for costs recovery. There are costs associated with providing this opportunity.

The Board notes that the costs associated with the hearing process represent a minute portion of the revenue requirement. Given that the regulatory process provides a full and fair opportunity for the Applicant and all stakeholders to pursue their interests before an impartial adjudicative body, and given that costs allocated to the utility are themselves subject to Board review and control, they cannot be said to be imprudently or unreasonably incurred.

The Board approves the Applicant's proposal, and finds that the allocation of such costs to Kitchener is appropriate.

Allocation of Sales Meter Related and Structures Related Costs

Union's Position

In E.B.R.O. 499, the Board directed Union to '..provide greater support and justification for its allocation of the costs of structures related to town border stations and of sales meters to Rate 01 customers in the Northern and Eastern Operations area in the next rate case.'

Union stated that the pool of costs in the Distribution - Structures and Improvements account were allocated to rate classes using a single allocation factor, as was generally accepted for cost allocation purposes. In Union's submission it would be impossible to determine which specific costs might be allocated to any particular rate class from a pool of costs.

In accordance with the Board's Uniform System of Accounts, Union has reclassified actual meter costs for town border stations in the Distribution Meters category, and allocated them to rate classes in proportion to meter plant costs. Regulating costs were reclassified to Distribution Regulators accounts. The demand component costs were allocated to rate classes in proportion to design day peak including T-service and Bundled T. The customer costs were allocated to rate classes in proportion to average customer numbers.

Union stated that structures and fencing were part of the Distribution Structures and Improvement costs and these costs have the same qualities as the Land and Land Rights plant accounts. In Union's view, these costs were allocated on a pooled basis and it was neither practical nor appropriate to isolate particular components of these accounts. Union also pointed out that the impact on Rate 01 was less than $150,000.

Intervenor's Position

Schools argued that the sales meter related costs, structures and fencing, should not be allocated to R01 but to larger rate classes only.

Schools objected to the shift in the functionalization of intangible plant in the Northern Operations areas to distribution only instead of across storage, transmission and distribution.

Board Findings

The Board accepts Union's argument that it may be impractical to isolate a particular expense or a capital item when the pooled concept is used for functionalization and allocation. The Board approves Union's proposal.

Delayed Payment Charges and NSF Cheque Revenue

Union's Position

Union submitted that Delayed Payment Charges, NSF Cheques revenue and collection costs were allocated to rate classes using the weighted average number of customers, as the costs were more related to the number of customers and the number of bills issued rather than volumes consumed. Bad debt expense was allocated between gas supply-related bad debt, which was allocated based on volumes, and delivery-related bad debt, which was allocated based on the weighted average number of customers.

Union was not able to locate the original analysis describing the weighted average number of customers factors. However, Union stated that the methodology was approved by the Board when Union and Centra first started using cost studies.

Intervenors' Position

Schools was concerned that a higher percentage of the collection costs and bad debt was allocated to the commercial portion of the M2 class and submitted that these costs and NSF Cheque revenues should be allocated between M2 residential and M2 Commercial customers based on volume.

School Boards was also concerned with the weighting factors used and requested a copy of the original approved weighting factor documentation.

Board Findings

Union's methodology for the allocation of these items is based on the principle that each category can be safely assumed to vary according to a weighting methodology which applies costs in proportion to the raw number of transactions. By this method Union allocates these items among rate classes. While the Board sees an intrinsic logic to the application of weighting to the number of transactions, it appears that the weighting used may yield anomalous or unreasonable results. The Board approves Union's allocation of these items according to its current methodology but requires Union, at the time of its next rates application, to present a detailed description and rationale for the weighting methodology used.

M9 and M10 Rate Class and Other Cost Allocation Issues

Union's Position

Union accepted that there may be validity to the position that the M10 rate class ought not to be included among the major market customers. Union suggested that allocation methodologies may occasionally have the effect of imposing small amounts of costs to rate classes that may not in fact contribute to the costs. Union suggested that in such cases, provided the amounts so allocated were not material, the methodology should be retained. In its view, this was such a case.

Union did not object to any proposal aimed at increasing the quality of the cost study. Union maintained that it does employ adequate checks and balances to ensure the accuracy of the cost study. Union submitted that after the cost allocation study had been completed, the results were compared to the previous Board-approved study. Any changes and shifts were analyzed and resolved.

Intervenors' Position

WGSPG submitted that Union adopted the WGSPG evidence related to the reduction in volumes of one of its members, and Union agreed to reflect the change in the draft rate order.

WGSPG requested that the Board direct Union to review its cost allocation model with respect to the M10 rate class. As discovered in the proceeding, a number of small errors have been noted. WGSPG submitted that it was important that the allocated costs be accurate and reasonable for all rate classes.

School Boards complained that Union did not use a "sanity check" to determine whether the resulting allocation to the various classes was reasonable. Others submitted that Union should have a more acute quality control method for reviewing the results of the cost allocation study.

Board Findings

The Board notes that some minor anomalies may occur in the application of an allocation method. The Board encourages Union to continuously refine the cost allocation study to address the identified inconsistencies.

Cost Allocation Summary : Board Findings

The merging of Centra Gas Ontario Inc and Union Gas Limited occurred on January 1, 1998 and after six years, there are still important gaps in the integration of these systems from a cost classification point of view. The reasons cited for the lack of progress in the harmonization of the systems are that the accounting systems and distribution systems are different. The Board notes that in this proceeding, Union pooled plant and O&M costs from the various operations areas for cost allocation purposes. The Board is concerned with the lack of progress made in bringing these systems together and directs Union to provide a detailed program for the complete integration of the respective operations areas in all aspects at the time of the next rates application.

The Board approves Union’s cost allocation study but notes that such undertakings are complex and susceptible to calculation, and even methodological anomalies. Where such irregularities arise, Union must act decisively and quickly to address them.

9.2 RATE DESIGN

Rate Design Principles

Union stated that rate design principles require that rates be designed according to common rate class criteria based on load factor, contract demand levels, load profile and quality of service.

Rate Design Proposals

Rate M2/Rate 01 Monthly Charge

Union proposed to increase the monthly charge to Rate M2 and Rate 01 from $10 to $14 per month. This proposal would have the effect of increasing the recovery of fixed costs through the fixed monthly charge from 41% to 57% for the Southern Operations Area and from 64% to 90% in the Northern and Eastern Operations Area.

Volumetric charges in M2 and Rate 01 would be reduced to achieve class revenue neutrality. This means that low volume M2 customers would experience an increase and higher volume M2 customers would experience decreases as illustrated in the table below. The annual delivery bill impacts for residential customers would be:

Rate	**2,300m^3**	**2,600m^3**	**2,900m^3**
M2	$8.60	$3.46	($1.68)
	2.6%	1.0%	(0.4%)
R01	$5.24	$0.08	($5.02)
	1.2%	0.0%	(1.0%)

Union submitted that the average residential customer consumes approximately 2,600 m^3 of gas per year, and for M2 customers consuming 2,300 m^3 year, the increase was less than $1.35 per month. The impact would be less for R01 customers.

Rate 10 Monthly Charge

Union proposed to increase the monthly charge for Rate 10 from $50 to $70 per month. The recovery of fixed costs through fixed monthly charges would increase from 51% to 71%. This change would align Rate 10 with Rate 16 which is the interruptible counterpart to Rate 10. Volumetric charges in Rate 10 would be reduced to achieve class revenue neutrality.

M5A Interruptible Monthly Charge

Currently, all costs allocated to rate M5A are recovered through volumetric rates. Based on the 2004 cost allocation study, customer-related costs allocated to M5A were approximately $1.4 million. This represents approximately 15% of the allocated fixed costs and 12% of the total allocated costs. As a result, large volume customers within the class pay a disproportionate share of the fixed costs.

Union proposed to introduce a monthly charge of $500/month which will recover 74% of the customer related costs.

Union stated that since the proposal is intended to be revenue neutral across each rate class, there is no material impact on conservation or bad debt expense.

Union stated that the increase in the fixed monthly charge allows for a better matching of customer related fixed costs with their recovery, and any delay would extend the subsidy of low volume users by large volume customers.

Intervenors' Position

The majority of the intervenors accepted Union's proposal to recover a greater percentage of fixed costs through the fixed monthly charge to enhance the fairness of rates.

Some intervenors were concerned with the magnitude of the $4.00 increase for M2 and R01 customers. They also suggested that by recovering more costs through fixed charges, Union was reducing its exposure to revenue risk and the return on equity should be adjusted to reflect the reduced risk.

VECC did not support the increase in fixed cost recovery. VECC contended that rate design did not have to mirror the findings of the cost allocation study and that there was no consistency in fixed costs recovery from different classes. VECC was also concerned that the fixed cost had been raised many times in the past two years, and the impact on low volume ($1800m^3$ / year) M2 customers had been an increase of 6%. VECC was also concerned that the decrease in variable cost would send the wrong signal to consumers to consume more gas.

Board's Findings

Some intervenors suggested that the increase in fixed costs would result in higher bad debt, and conversely, the lower variable cost would encourage higher consumption. Since the effect of the increased fixed charge and the decreased volumetric charge is neutral, the Board cannot accept the intervenors' conclusions.

Some intervenors have suggested that the proposed increase in fixed charges has an impact on Union's business risk that should be reflected in an adjustment to the ROE. This aspect of Union's proposals addresses but one of many business risks that affect Union's overall risk exposure. Parties are free to provide evidence in subsequent proceedings which addresses the setting of the utility's risk premium. In the absence of evidence on this issue in this case, the Board is not prepared to make any finding on this issue.

The Board accepts that increasing the fixed customer charge for the stipulated rate classes is a measure which has the effect of increasing the recovery of fixed costs and reducing intra-class subsidy and is an appropriate element of rate design. However, the Board is concerned that the magnitude of the proposed increase has the potential to cause concern among low volume gas consumers, who would experience increases in their total annual bills. While the increase reflects cost causality, the Board finds it preferable to phase in the proposed increase over a two-year period. Therefore, the Board will approve the following for 2004: M2 - an increase from $10.00 to $12.00; Rate 10 - a monthly charge of $70 per month; and M5 - a monthly charge of $500/month.

M2 Rate Design

Intervenors wanted to split the M2 class based on volumes to reduce intra-class subsidy.

Union's Position

Union submitted that its rate design principles did not include end use as a criterion. Union noted that Schools did not support School Boards' proposal to split M2 based on end-use. Union noted that the M2 split in the cost allocation study was reliable for rate design purposes but was not appropriate, or accurate enough, to be used in the design of sub-rates for Rate M2.

Union stated that M2 consists of all residential and non-contract commercial/industrial customers in Union's Southern Operations area. Union added that while there was wide variability in the class in terms of nature of business and total annual load, on the whole, M2 customers have similar load profiles.

Union stated that its present system did not accommodate the imposition of a 'special charge' to customers designated as commercial/industrial. Union does not have accurate information so as to enable it to designate customers according to these categories, especially at lower volumes.

Union rejected the intervenors' requests that Union study splitting the M2 class based on volume. If the Board directs Union to perform such a study, the costs incurred should be recoverable.

Intervenors' Position

Most intervenors agreed that M2 consists of a wide range of customers and supported a split in the M2 class to reduce intra class subsidization and improve revenue to cost ratios. However, there were different views as to how the split should be effected.

School Boards submitted that Union should split M2 based on end-use categories (commercial and residential) similar to Enbridge's Rates 1 and 6. School Boards noted that since Union separates residential and commercial consumers for cost allocation purposes, rate design should reflect the same split. School Boards also noted that at one time there were two rate classes namely, Rate M1 and Rate M2.

Schools, EDGI, IGUA and VECC supported splitting the M2 rate class, based on volume.

Board Findings

The Board agrees that rate design principles typically do not include end-use categories. However, the Board is not convinced that the load profile for commercial/industrial customers is so similar to that of residential customers as to be functionally indistinguishable. It is counter-intuitive that a high volume industrial user will incur the same amount of customer related costs as a residential customer. It seems unreasonable that Union cannot differentiate members of this class on the basis of consumption. The Board therefore directs Union to conduct a cost allocation and rate design study directed at separating low volume and high volume consumers currently within the M2 rate class. In designing the study, Union should consider rate implications at different volume breakpoints and should also consider the appropriate level of monthly fixed charges for each sub-class. The results of this study shall be filed with the 2005 rates application. The Board agrees that the reasonably incurred costs of this study should be recoverable in rates. The Board does not believe that a deferral account is an appropriate instrument for this purpose. Union should bring forward its claim for costs related to the study in subsequent rate proceedings.

M6A Seasonal Service

Union's Position

Currently, to be eligible for service under rate M4 and Rate M5A, contract customers must take at least 700,000m^3 per year.

Union proposed to extend this requirement to the rate M6A service on a proportional basis to reflect the seven month availability of the seasonal rate M6A service. Union proposed to add the following clause to Section (C) Rates of the M6A rate schedule: "For each April 1 to Oct. 31 contract period, the customer shall take delivery from Union or in any event pay for a minimum volume of gas transportation services which will not be less than 400,000m^3".

Board Findings

The Board approves Union's proposal to add a minimum contract volume to the M6A seasonal service. There were no submissions respecting this proposal and it does not affect the rate level and revenue requirement for the class which has been approved in a previous rate case.

M12 Transmission Fuel Rate Changes

<u>Dawn Fuel Factor M12</u>

Union proposed that transmission related Dawn compressor fuel requirements be extended by two months, so that April and October are included in easterly fuel ratios.

Parkway-to-Parkway Fuel

Union proposed to add to the M12 rate schedule a Parkway-to-Parkway fuel ratio to recover fuel and unaccounted for gas associated with moving gas between Union's Parkway compressor station and EGDI's Parkway compressor station.

Parkway Compressor Overrun

Union proposed to add to the MI2 rate schedule a Parkway Compressor Overrun charge to recover incremental fuel incurred when customers deliver more than their contractual entitlement for compression at Parkway (TCPL) in any given month. The addition of the Parkway Compressor Overrun charge will ensure that the customers driving the incremental fuel requirement at Parkway (TCPL) bear the cost responsibility.

Other M12 Changes

Transportation - Union also proposed changes to Schedule" C" of the M12 rate schedule to better clarify the applicability of the VT1 easterly fuel ratios.

Storage - Union has added a note to the M12 rate schedule that effective March 31, 2004, Union will no longer be offering M12 cost based storage services to ex-franchise customers. This timing was consistent with the expiry of M12 cost based storage contracts.

Board's Finding

There were no submissions respecting Union's proposals which are outlined above. The Board approves Union's proposals.

M13 Rate Class

Background

Energy Objective submitted that the proposed M13 Rate is not just and reasonable for Ontario producers.

Union's Position

Union submitted that the balancing fee was set through negotiation in September 1995 and was not subject to Board approval. Ontario producers are not obliged to sell to Union and may sell their gas at Dawn in the competitive market.

Union stated that Energy Objective's assertion that Ontario production gas was used to service local markets was irrelevant. On any given day, including peak days, there may be no gas deliveries from Ontario producers. This is the rationale for Union's imposition of a balancing fee for the gas producers.

Union submitted that the proposal to apply the monthly fixed charge based on the number of local producer stations was more appropriate because it conforms with the principle of cost causality.

Union stated that the M13 transportation commodity charge was designed based on meeting Union's contractual obligations to its customers and not based on physical flow.

Union submitted that Dawn/Trafalgar assets were used in the transportation of Ontario producers' gas to Dawn. Union stated that 100% of the M12 Dawn to Parkway (excluding Dawn compression) demand charge was used as a proxy for the actual cost of transporting gas from the local producer station to Dawn. Union stated that the evidence shows that the M12 rate reflects the value of the transportation service from the local producer station to Dawn.

Union stated that the treatment of Dawn/Trafalgar costs has been in place for many years and was reconfirmed by the Board in its E.B.R.O. 493/494 Decision:

> "The Board finds that the fact that at design conditions, delivery of east end volumes (14,122, 103m^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." (E.B.R.O. 493/494 Decision with Reasons, dated March 20, 1997, para. 9.4.37)

Further, the Board found:

> "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." (E.B.R.O. 493/494 Decision with Reasons, dated March 20, 1997, para. 9.4.37)

Union submitted that the Board's E.B.R.O. 493/494 Decision, dated March 20, 1997, para. 9.4.37 was equally applicable to the M13 customer taking transportation service on Union's system.

Union stated that it was difficult, if not impossible, to track physical flow. Union's operations vary from day-to-day and recovering cost of facilities solely based on physical flow may conflict with the 'postage stamp' principle of rate making.

Union's response to Energy Objective's argument that the revenue to cost ratio for M13 was greater than one was based on the fact that Union did not allocate any costs related to the transportation of gas from the local producer station to Dawn to the M13 class in the cost allocation study. This was why the revenue to cost ratio was greater than one. However, the costs were reflected in the rate design.

Union submitted that local producers have the right to apply for bypass and it would be within the Board's jurisdiction to grant or deny the applications.

Union submitted that there was an obligation for direct purchase customers to commit to delivery at Parkway and the reasons for this were dealt with in the context of the DCC elimination in RP-2002-0130. If Union was to accede to Energy Objective's request, then the obligation of the direct purchase customers should also be relieved. This would result in increased capital spending to accommodate winter peaking and in higher rates for all customers.

Union proposed to apply a fixed charge of $502 /month/station, to the Rate M13 and Rate M16 on the basis of number of stations related to each customer. This change was necessary because the number of customers had been reduced. The fixed charge is intended to recover the cost of the meter, regulators, odourant tanks, land, land rights and other aspects associated with the local producer.

Intervenors' Position

Energy Objective expressed concerns with Union's spot purchases of Ontario gas, stating that the methodology used by Union involved purchasing gas from Ontario producers on a spot basis using a monthly Niagara index. Union maintained that the acquisition of Ontario gas production is not a spot purchase, but instead part of Union's planned purchases. Energy Objective took the position that this type of arrangement was more consistent with a spot purchasing methodology. In this context, Energy Objective noted that Union deducts a $0.24 per gigajoule charge for transportation and balancing. Energy Objective stated that both its evidence and that of Union support the view that Ontario gas production is consumed by local markets and helps to balance that market. Therefore, Energy Objective concluded that the application of a charge for transportation and balancing is inappropriate. They requested that the Board deny Union's use of this methodology and order Union to purchase Ontario gas production using a Dawn or Niagara monthly index without any deductions.

Energy Objective submitted that Union failed to prove that Dawn-Trafalgar assets associated with the M12 rate were required for the purpose of transporting Ontario natural gas production to Dawn. Energy Objective also stated that the old requirement to move gas to an ex-franchise point (Dawn TCPL) in order for Ontario producers to market gas to third parties no longer exists. Energy Objective submitted that Ontario producers used local distribution at lower pressure and that notional service did not require compression. On the other hand, Energy Objective argued that it provides compression to get production gas into Union's system.

Energy Objective submitted that it was within Union's franchise area and should not require upstream transportation. It requested that the Board direct Union to remove the Parkway delivery commitment from Ontario producers. This would provide a benefit to the province and would not favour one marketer over another.

Energy Objective submitted that the revenue to cost ratio for the M13 class being in excess of one, is too high.

Board's Findings

Union operates a fully integrated gas distribution system. Its operation is dependent upon the maintenance of a balanced series of inputs and outputs. Gas supplied by Ontario producers necessarily augments and displaces other sources of supply within the pipeline. The fact that any given producers' gas contribution to the system may be withdrawn prior to the end point of the distribution system should not result in any particular or preferential treatment. It is impractical and inefficient to attempt to track specific gas molecules within the system in order to tune transportation charges according to presumed and unverifiable distances. Such a practice would be inconsistent with the most cost effective operation of a fully integrated broad service distribution network. Accordingly the Board rejects Energy Objective's submission with respect to this rate class.

The Board has elsewhere in this decision expressed the view that it regards local production to be an important aspect of the province's overall energy environment. Issues surrounding its development may well be better explored in an appropriate policy forum.

The Board approves Union's proposal to apply the monthly fixed charge on the basis of the number of stations related to each customer, instead of the number of customers. This is necessitated by the reduction of the number of customers as a result of consolidation of local producers. Since the fixed charge is intended to recover the cost related to station operations, it is reasonable to apply the fixed charge based on the number of connections instead of the number of customers.

M15 Rate

Union's Position

With the termination of the Joint Venture Agreement between Dow Chemical Canada Inc. and Union, the rate M15 rate schedule was no longer required. Union will therefore eliminate the rate M15 rate schedule with the implementation of 2004 rates.

Board's Findings

The Board approves the elimination of the M15 rate class as Union's joint venture with Dow Chemicals has terminated. There were no submissions with regards to this proposal.

M16 Rate - Northern Cross Energy Limited (NCE)

Background

NCE produces natural gas in Ontario and has an application before the Board for the approvals necessary to develop the Ashfield Pool as a storage asset. The Ashfield Pool is connected to Union's distribution system in the area near Goderich.

NCE believes there is significant demand for distributed storage and potential for new storage development in Ontario. NCE submitted that, currently, these developments were being frustrated by the inappropriate rate structures offered by Union.

Union offered a M16 rate which was previously designed to provide bi-directional gas flow from and to Union's Tupperville metering station the Chatham D Pool, presently operated by EGDI. While NCE has been involved in discussions with Union, seeking a new rate for injection and withdrawal of gas to and from the Ashfield Storage Pool, it did not participate in the ADR and was not active in the oral hearing.

Northern Cross Energy's intervention in this case raises two issues:

1. the accessibility of independently operated storage pools, and

2. whether Union's reliance upon an M16 rate is an undue deterrent to the development of such pools.

Union's Position

Union acknowledged that it has been engaged in negotiations with NCE to develop a rate that was acceptable to both parties.

Union contended that the M16 rate was applicable and pointed out that another independent storage developer had accepted the M16 rate for transporting gas. As a result, the capacity has been fully contracted such that, contractually, there is no capacity available to NCE.

In response to NCE's assertion that the C1 rate was not appropriate, Union submitted that in the case of the Ashfield Pool, the primary transportation system was the Dawn/Trafalgar system. As a result, the Dawn/Trafalgar demand charge contained in the C1 rate schedule was applicable to NCE for the transportation service.

Union noted that this is consistent with the demand charges Enbridge pays for transportation service between Ojibway and Dawn on Union's Panhandle system. Union submitted that the same approach should apply to NCE.

Union submitted that Unaccounted For Gas (UFG) was not charged based on gas lost through leakage and line breaks. UFG was charged for the variance between the meter reading at the pool and any other point on Union's system. As such, UFG was applied to all customers transporting gas on Union's system.

Union argued that it was contractually obligated to provide volumes equivalent to the locally produced volumes on the same day at Dawn. Union submitted that there was no evidence that allocating costs based on physical flow would result in a more accurate cost allocation factor, nor that the results would be more reliable and less variable.

Union submitted that the proposed Ashfield Pool would not provide a facilities benefit to Union because it could not be counted on to meet demands on design day. NCE did not provide evidence to support its argument that the pool would delay or avoid capital expenditures to maintain and enhance the system.

Union submitted that it competes in the storage market through its connections with upstream pipelines and there was no evidence that new storage development in Ontario would impact Union's ability to generate storage revenue.

Intervenor's Position

CEED suggested that the Board should consider the advantages that may be realized in a competitive merchant storage market populated by independent storage companies without the market power that comes from being integrated with a transmission and distribution utility.

The M16 rate was specifically designed for a gas transportation service between the Chatham 7-17-XII Pool and Dawn. The rate structure consists of: a monthly fixed charge, a fixed monthly demand charge for gas withdrawn from the pool in the winter, a fixed monthly demand charges for gas injected into the pool in the summer, commodity charges on volumes injected and withdrawn and commodity fuel charges and unaccounted for gas charges on volumes injected and withdrawn.

According to NCE, only one customer was taking service under the M16 rate schedule. NCE submitted that the same rate schedule should not be applied to its operation. The M16 rate was onerous for storage pools not situated in close proximity or directly connected to Union's storage at Dawn. This created an uneven playing field and hindered any new storage development in Ontario by independent operators.

NCE submitted that the M16 rate structure would require NCE to pay firm demand charges for the use of the Dawn/Trafalgar transmission facilities in both directions for 12 months of the year. NCE stated that this treatment should not apply to its storage operations, and suggested that during the winter, gas withdrawn from storage would move no further than local area distribution loads and may reduce the need to move gas on Dawn/Trafalgar to serve those distribution loads.

NCE further submitted that using transportation service contract parameters to set storage service rates was not cost justified. NCE suggested Union should study how the storage operator actually impacts on Union's system and then allocate costs accordingly. NCE believed that the cost shifting to accommodate one storage operator should not have any material impact on the other classes.

NCE pointed out that injections and withdrawals from a storage operator would be metered by Union but paid for by the storage operator. It was therefore not logical that the storage operator should pay for additional unaccounted for losses on Union's system when the gas injection and withdrawal were measured at the same point.

NCE submitted that Union should design a rate for the embedded storage operations taking into consideration, their unique ability to receive and deliver gas to the system, the potential to defer or avoid system expansion, to increase system reliability and security and to increase market liquidity and price leveling, that can benefit all system customers. NCE submitted that without direction from the Board, Union as the largest storage operator would not have any incentive to develop reasonable rates for independent storage operators.

NCE proposed that the storage operator be offered a service of a lower priority than that provided to consumers and producers. NCE submitted that by connecting embedded storage to the distribution system, and having injections and withdrawals after the needs of distribution loads have been satisfied, meaningful benefits would be provided for all system customers.

NCE claimed that:

1. Storage connections regularly take gas both on and off the system;
2. All system customers benefit from and may use storage;
3. Storage facilities may avoid or delay future capital expenditures;
4. Storage provides intrinsic value, such as increased market liquidity, price leveling and enhanced system efficiency and integrity.

NCE submitted that Union should recognize these benefits in setting rates for embedded storage operations.

Board's Findings

The Board accepts that the safe and prudent development of new storage facilities is in the public interest.

The Board notes that Union has claimed that the M16 rate schedule was accepted by EGDI to access the Chatham D Pool. The Board notes that Tribute Resources has entered into an M16 service agreement for delivery/re-delivery service to their proposed storage project. The Board does not consider Tribute's acceptance a compelling or reliable demonstration of the appropriateness of Union's classification.

NCE submitted that by connecting embedded storage to the distribution system and having injections and withdrawals after the needs of distribution load have been satisfied would provide benefits for all system customers. Union's response was that since Union had reached an agreement with another storage developer the capacity to and from the Ashfield pool was no longer available. Based on Union's statement, there may or may not be benefits to the overall system depending on the location of the embedded storage pool.

The Board finds that the evidence lacks the necessary detail to enable the Board to make a determination.

The Board does not have sufficient evidence before it to assess the extent to which the claimed lower priority of service and the benefits to the system justifies, on the basis of generally accepted rate design principles, a unique rate class for such undertakings.

The Board considers that the benefits NCE postulates, arising from its ownership and operation of the contemplated storage pool, are tangible and may be realizable. If so, the appropriateness of classifying NCE as an M16 customer is unclear. At this time, it appears there is a need to investigate the classification of customers who do not neatly satisfy the eligibility criteria of existing rates.

The Board directs Union to review the cost causality associated with NCE’s storage operations with special emphasis on the allocation of storage costs. Union should take into consideration the reduced level of service and the ability of a storage operation to inject and withdraw at a different rate and time versus the service requirements of a pure gas consumer in its rate design. The Board also directs Union to review the cost allocation and rate design applicable to distributed storage pools such as the Ashfield Pool and submit such evidence as part of its 2005 rates application.

Rate R1 - Discretionary Gas Supply Service ("DGSS")

Union proposes to sell gas to direct purchase customers who are unable to access supplies to meet their February 28 checkpoint.

Union’s witness testified that the service was required by many customers and identified several customers who have had difficulty purchasing blocks of gas supply at Dawn to balance. In some cases, the credit requirements were onerous.

Union further stated that Discretionary Gas Supply Service ("DGSS") was just an additional service to meet a need of customers. Union would not purchase the gas until the customer has committed to purchase the gas from Union. Union stated that this service would have no impact on the sales service portfolio in any way and was strictly a contract between the customer requesting the service and Union.

Union proposed to modify the wording for Rate R1 to allow for banked gas purchases at times other than contract expiry as a result of the proposed load balancing process. The revised wording would read: "The charge for banked gas purchases shall be the higher of the daily spot gas costs at Dawn in the month of or the month following the month in which gas was sold under this rate and shall not be less than Union's approved weighted average cost of gas."

Intervenors' Position

School Boards, LPMA, IGUA and WGSPG supported Union's proposal to supply small volume customers who may find it difficult to purchase a one-time small volume of gas on the open market at competitive prices.

CEED, School Boards and OESC were opposed. In their view, Union should not be permitted to offer DGSS in competition with other gas service providers. Some intervenors were concerned that the service may not be restricted to direct purchase customers but may also be accessed by customers who are able to access suppliers, but who do not prefer the terms and conditions governing such supply.

Board's Findings

The Board accepts Union's evidence that there are customers who may require this service. The Board has approved the load balancing proposal and hereby approves the necessary modifications to facilitate the implementation of the DGSS process. The Board directs Union to maintain records of all such transactions and make them available for audit by the Board.

T1 Rate

Union's Evidence

There have been some significant increases in the number of customers and the volumes consumed in the T1 class. This has resulted in greater diversity. Annual volumes can range from 5,000 10^3m^3 to 400,000 10^3m^3.

Union proposed the introduction of a common customer charge of $1,800 for all T1 customers, regardless of size. Union submitted that the change to a single fixed customer charge would be more equitable. Union proposed a two-block demand charge with a breakpoint of 140,870 m^3/day. Union also proposed to split the commodity rate into two blocks with a breakpoint of 2,360,653 m^3/month. This would align the rate T1 blocks with rate M7. The proposed rate structure would provide better alignment with cost recovery and reduce intra-class cross-subsidy.

The rationale for the changes was to smooth the relative price differences between rate classes at the rate class boundaries and to maintain proper relationships between bundled and storage and transportation services. In addition, the changes are intended to ensure that storage and transportation service pricing would not create an inappropriate incentive for customers to switch. Finally, the changes are intended to reflect the relationship between revenue and allocated costs for the T1 class.

Intervenors' Position

IGUA was concerned that the small volume T1 customers would see an increase of approximately 23%. Coral Energy Canada Inc. also expressed concerns.

Board's Findings

The Board recognizes that the problem of intra-class subsidies more readily occurs when disparate variations in annual volume exist within a customer class. The Board accordingly approves Union's proposal to revise the rate structure to introduce a two block demand and two-block commodity rate and to increase the fixed customer charge.

T3 Rate

Union's Evidence

Union is not proposing any change to the negotiated contracts that fall within this rate class.

Union reiterated that the T3 rate design is based on contractual obligations and used contractual parameters for setting rates. Union submitted that Kitchener had a contractual Contract Demand (CD), and it was appropriate to maintain the integrity of the contract. The issue of a new CD could be left to negotiations for the next contract.

Intervenors' Position

Kitchener took exception to Union's forecast of Kitchener's volume requirements for the test year. Kitchener submitted that Union did not set an appropriate level of CD for the T3 class in the rate design. Union based the rate design on 1,911 10^3m^3 whereas Kitchener's peak demand was 2,557 10^3m^3. As a result, the unit rate was higher as the same revenue was spread over fewer units.

Kitchener agreed with Union that there was no obligation to accept a customer's suggested CD for rate making purposes in a multi-customer class, but when there was only one customer in the class, Union should recognize that the customer may be in a better position to forecast its CD.

Kitchener requested that the Board direct Union to review the design of T3 rates or approve the proposed T3 rate as interim and direct Union to negotiate a proper CD with Kitchener.

Board's Findings

The Board was advised by Kitchener's counsel on January 22, 2004 that the parties have arrived at a settlement and wish to withdraw the request for relief. The Board approves this request.

It is not the Board's primary role to arbitrate commercial contracts entered into by sophisticated and competent parties. Elsewhere in this decision the Board has indicated the importance it places on the development of Contract Demand forecasts on a consensual basis.

Other Rate Schedule Changes

Union's Position

Union proposed to make some changes to enhance rate schedule clarity and provide for consistent wording between contracts and the rate schedules.

Union proposed to standardize the late payment policy (1.9% monthly compounded late payment charge, commencing 16 days after issuing the bill) across all in-franchise rate classes in both the Southern Operations Area and the Northern and Eastern Operations Area.

Board's Findings

The Board approves the proposed changes to make the 2004 Rate Schedule more accessible. There were no submissions on this proposal.

9.3 CORAL ENERGY ISSUES

Background

Coral Energy Canada Inc. ("Coral") intervened in this proceeding to seek the Board's approval for a rate to govern the supply of gas by Union to the Brighton Beach Gas-Fired Electricity Generation Facility located at Windsor Ontario.

Coral has entered into a tolling agreement with the owners of the Brighton Beach facility, pursuant to which it provides gas to fuel the generation equipment, and then sells the electricity generated into the IMO-administered electricity market. Accordingly, the price of gas was a consideration for Coral in the overall profitability of its undertaking in connection with the Brighton Beach facility.

The Brighton Beach facility itself is a joint venture between OPG and ATCO. It is designed to deliver electricity into the IMO-administered market at times when a premium price was being offered for incremental generation. This will normally occur at times when other sources of supply are unable to meet the system demand.

Coral and Union engaged in a negotiation respecting the terms and conditions that would govern Coral's supply of gas to the facility. At one point, because negotiations had not been fruitful, Coral filed an application with this Board for Leave to Construct a gas connection, which would have bypassed Union's distribution system. Union filed a competing Leave to Construct application. Negotiations resumed and Coral withdrew its application, and Union's was granted.

Coral and Union entered into a Carriage Service Contract ("CSC") on April 30th, 2002, the purpose of which was to define the terms under which Union would transport gas to the Brighton Beach facility. The parties subsequently entered into a related Clarification Agreement.

A key component to the pricing arrangement codified in the contract was the Delivery Commitment Credit ("DCC"). The DCC was an artifact of the rate structure governing direct purchase arrangements, which rewarded direct purchase customers who had met their contractual obligations to Union with payments which were, in effect, rebates. The DCC had been put in place in the early stages of the unbundled marketplace as a financial device intended to encourage system customers to opt for the unbundled direct purchase option. As the unbundled market developed, all participants came to appreciate that the DCC should in some fashion be eliminated, insofar as it represented a device whose utility had been overcome by the development of the market.

In the Alternative Dispute Resolution conference leading up to the RP-1999-0017 case, an agreement was reached between all participants that the DCC should be eliminated. Union made a proposal to do so in RP-2001-0029, which would have eliminated the DCC per se, but which would have also retained the value of the rebates made attendant to the program by building them into the very rate structures governing the direct purchase customers. That same proposal was made in RP-2002-0130. Many interveners rejected Union’s proposal as not genuinely eliminating the device, insofar as it built the rebates back into the rate structures. This was not, they contended the termination of the program, but rather its entrenchment. In RP-2002-0130 the Board found that the DCC should be eliminated in its entirety, so that the rebates rewarding direct purchase customers for meeting their contractual obligations to Union would be discontinued and not re-entrenched in the rate structures. In order to mitigate the effect of the elimination of the rebate on direct purchase customers, the Board determined that its elimination should be transitioned over a five year period, one fifth of the rebate to be eliminated in each year until the DCC was completely eradicated.

It was clear that the DCC rebate program was an important feature of the original contract for carriage between Union and Coral. It even appears that the Daily Contract Quantity ("DCQ") figures represented in the agreement were unnaturally high in order to increase the extent of the DCC rebate, and hence lower the overall cost of gas supply to Coral. It also appears that the full extent of the DCQ may not have been unequivocally obligated.

Once the DCC had been eliminated, the attractiveness of the initial contract for carriage to Coral was compromised. Indeed, the Clarification Agreement contained a provision which addressed the possibility that the Board would eliminate the DCC in a manner different from that proposed by Union in RP-2002-0130. That provision required Union to use its best efforts to arrive at a new rate proposal for Coral which would preserve the essential economics of the transaction for Coral, given that now, following the Board's decision in RP-2002-0130, the DCC was not an ongoing source of rate rebate.

Union stated that it had examined the issue, and had concluded that there was no basis upon which it could establish a non-DCC rate that was as attractive to Coral as was the original arrangement.

Coral sought the Board's intervention to compel a rate treatment from Union that approximated its original expectation as to the cost of gas for the Brighton Beach facility.

Union's Position

Union submitted Coral's request was without merit and not supported by the principles of sound rate design.

Union submitted that Coral's request amounted to a request for the Board to vary its decision with respect to the elimination of the DCC for Coral alone among Union's other customers.

Union stated that the Board recognized the significant net rate impact resulting from the elimination of the DCC by directing Union to phase out the DCC over a period of five years.

Union argued that whether Coral was a credible bypass candidate was speculative since Coral withdrew its application for leave to construct before written interrogatories in respect of Coral's evidence were delivered. It was never the subject of cross-examination nor was this evidence put before the Board by Coral in this case.

Coral provided no evidence relating to its costs. Coral stated that gas distribution charges represented just 1% of Coral's total operating costs and just 2% of the total gas costs.

Union stated that the rate offered in the CSC was not a bypass rate, it was the T1 posted toll in effect at the time, adjusted to reflect Union's proposal to eliminate the DCC. Union did not offer any inducement for Coral to drop its bypass application.

Union presented evidence on the difference between Union's and Coral's understanding of the obligated DCQ.

Union argued that Coral's profile was not unique and its load and load profile were similar to other T1 customers. The firm transportation demand provided to Coral was approximately 87% in the CSC. It was only the total load factor which was projected to be 47%. Even at this level, it was within the T1 class average.

Union submitted that it had other high volume, low load factor customers. The costs associated with serving these customers were typically higher because capacity becomes idle. Accordingly, Union submitted that assuming Coral did display such unique characteristics, it should pay a higher as opposed to a lower rate.

Union strongly supported the Board's recognition of postage stamp rates as the basic building block of utility regulation in Ontario.

Union denied Coral's claim that the Board should consider other additional factors forming part of the 'public interest' argument.

Union submitted that there was no legislative support that 'the proposed rate appropriately balances the interests of natural gas and electricity market." If this amounted to the M2 or other Union customers subsidizing the cost of electricity across Ontario, then it may not necessarily be in the public interest.

Union questioned Coral's assertion that Ontario electricity customers will save $5 to $9 million per year, which divided by the 2001 census number of household in Ontario would result in an alleged savings of $1.20 to $2.15 per household. Coral claimed that this would cost the Union customer $1.6 million which translated to $1.90 per household in the Southern Operations area.

Union submitted that Coral's argument of 'unforeseen consequences of rate decisions' was also without merit since Coral took no active part in either the RP-2001-0029 or the RP-2002-0130 case.

Union also rejected Coral's assertion that Union was engaged in some sort of 'Gotcha' game with Coral. Union was indifferent as to the specific rate charged to Coral as long as Union recovered its revenue deficiency.

Union submitted that it had considered Coral's request for rate relief in the context of the Board's decision with respect to the DCC, accepted principles of rate design, and Board precedent related to bypass competitive and postage stamp rates. Union could not find any reasonable rate-making alternative that would allow Union to provide Coral with the relief sought.

Coral's Position

Coral entered into the 20-year Carriage Service Contract with Union on the understanding that: a) the DCC was to be applied to reduce the Monthly Demand Charge and b) Coral would not be required to deliver the DCQ at Dawn except for design days.

Coral stated that following the Board's RP-2002-0029 decision to phase out the DCC, Coral modified the CSC with a Clarification Agreement dated October 1, 2002. The parties agreed to add Section 5(e), which read: "If the OEB eliminates the DCC in a manner not consistent with Union 's proposal ....then Union will use all reasonable and prompt efforts to propose and implement promptly an alternate rate-making solution which shall provide a comparable economic benefit to Customer as that provided by the DCC." However, Union's position was that "Given the clarity of the Board' s Decision on the DCC... there was no reasonable rate-making justification or defense for providing to Coral demand charge relief which cannot be provided to any other similarly situated customer, namely the full benefit of the pre-RP-2002-0130 DCC payment in rates."

Coral submitted that in view of its position as a credible bypass threat to Union, its distinctive gas profile and operating characteristics as the first gas-fired wholly merchant generator in Ontario, and its reliance on the pricing mechanism contained in the CSC to withdraw its LTC application", Coral requested the Board to approve the rates for transportation service contained in the CSC.

Coral reiterated that it was not seeking to vary the Board's order but was seeking an alternate rate-making solution which would provide a comparable economic benefit to Coral as that provided for by the DCC.

Coral submitted that "..the traditional bypass competitive rates framework applied in pre-1998 cases requires further evolution to take into account of the changes wrought by the Energy Competition Act, 1998." Coral requested the Board to consider the following:

1. is Coral's load profile unique,
2. is it in public interest to approve a different rate for Coral, and
3. is Union's existing rate for Coral just and reasonable.

Coral submitted that it was a credible bypass candidate. Since being a member of the Royal Dutch/Shell family of companies, it had the required resources and capabilities to finance, construct, own and operate lateral pipelines. Coral stated it only withdrew its Leave To Construct Application on the basis that it relied on the pricing mechanism offered by Union in the CSC.

Coral submitted that even without DCC, Union will recover its incremental costs of constructing and operating the gas lateral pipeline and as such, it was in the public interest to approve Coral's proposed rates to reduce the price of electricity.

Coral submitted that during negotiations with Union in 2001, Union was unable to lower the net delivery costs to match the economics of Coral building its own pipeline. On April 30, 2002, Coral and Union entered into the CSC and Coral withdrew its National Energy Board and OEB LTC applications. Coral stated that the two key points in the CSC were the application of the DCC to the Monthly Firm

Demand Charge and that Coral would not be required to deliver the DCQ at Dawn except on design days.

Coral submitted that the operating characteristics of the merchant generator were unique due to its high volume/low load factor profile, and therefore, justified a different rate.

Coral argued that, in the past, the Board has stated in the 1993 Cardinal Power case "The question of public interest in not a question of fact, but it was a question of judgement based on the facts and circumstances before the Board. Since the facts and circumstances change from case to case, so will the depiction of the public interest."

Coral submitted that in Coral's case, the Board should take into account two factors involving the interplay between the natural gas and electricity markets namely, the impact of gas delivery costs on electricity prices and the relationship between gas delivery rates and the siting of generation plants.

Coral submitted that if the cost difference between the rates in the CSC and Union's 2004 T1 rates of $1.6 million in 2007 (based on Exhibit 22.4) was passed onto electricity consumers they will have to pay between $5 to $9 million more for electricity. Coral submitted that Ontario energy consumers will benefit by approximately $3.4 million to $7.4 million.

Coral submitted that the siting of the Brighton generation plant should reduce congestion constraints on the electricity transmission system. This could lead to avoided costs in constructing transmission lines. Coral urged the Board to take into account the broader picture of the energy market instead of looking at the gas sector in isolation.

Coral submitted that the public interest requires that Ontario's regulatory structure incorporate some flexibility to deal with unforeseen consequences of regulatory decisions.

Coral submitted that the Board's Decision in RP-2002-0130 did not, and could not, foresee the impact on the CSC between Union and Coral. Coral did not place the confidential CSC before the Board at the time because it was relying on Union to defend its DCC elimination proposal and its contract with Union to provide an alternative rate making solution in the event the Board did not accept Union's proposal.

Coral submitted that by accepting Coral's proposal, the Board will "signal to investors that the regulatory regime in Ontario can deal with the unintended consequences of regulatory decisions, thereby providing investors with confidence that regulatory charges will not undermine the fundamental tenets of contracts that define the understandings upon which investments were made."

Coral requested the Board approve revenue requirements for gas transportation service to Brighton Beach for a term of 20 years commencing January 1, 2004, equivalent to the revenue levels originally contemplated by the terms of the CSC. Alternately, Coral requested the Board to approve either Rate Structure 1 or Rate Structure 2 described on pages 13 and 14 of the Elenchus Report.

Intervenors' Positions

The majority of the intervenors agreed that the Board should not be involved in contracts between parties and should only be interested in the rate design issues. VECC submitted that a bilaterally negotiated price was clearly outside the scope of posted rates. The majority of the intervenors were concerned that if a special rate was offered to Coral, it would pose additional costs to other customers.

VECC submitted that Coral did not provide enough analysis of the existing T1 customer load profile, contract demand levels, or load factor to justify a special rate.

VECC and CAC submitted that Coral had missed the opportunity to request a competitive bypass rate. Coral withdrew its leave to construct application and also did not intervene in the previous two Union rate cases when the DCC was under attack. The Board was well aware of the consequences of the elimination of the DCC, and suggested phasing in the elimination over 5 years.

VECC and CAC suggested that Coral was using the Energy Competition Act, 1998 to persuade the Board to consider awarding Coral a special rate in consideration of sound public policy to lower the price of electricity.

CAC further submitted that it was not up to the Board to decide on having gas users subsidize electricity users. Such a decision should rest with the government. The stand-alone obligation for gas users to subsidize electricity users without reference to other forms of energy was incorrect.

VECC submitted that if the Board approved a special rate for Coral, any deficiency should be assumed by the T1 class and not by all rate classes as Union suggested.

VECC and TCPL submitted that Union’s shareholders and not the ratepayers should be responsible for the deficiency from actions concluded in private negotiations without regulatory scrutiny, including a prudence review of the contract.

CAC and LPMA agreed with Union’s rate making principles and felt that Coral’s request was a fundamental challenge to class rate-making principles. CAC stated that granting relief to Coral would inevitably result in a flood of applications by other members of the existing rate class, claiming that their end-use characteristics justified the creation of a distinct rate class.

CAC stated that Coral was aware of the regulatory risk in RP-2001-0029 to eliminate the DCC, and in the Clarification agreement, Coral did not withdraw from the agreement and accepted a "best efforts" undertaking on the part of Union.

A number of intervenors requested the Board to require a separate process to address the issues of gas distribution rate design and infrastructure requirements as they relate to gas fired electricity generation.

Board's Findings

The Bypass Argument

Coral's position begins with the suggestion that the rate arising from the Contract for Carriage was a rate that specifically responded to Coral's application for leave to construct the requisite gas connection facility, or in other words, was a bypass-competitive rate. At a minimum, in order for this argument to succeed, Coral must demonstrate that it was, and in some respects continues to be, a viable owner and developer of the gas connection, and that it fully intended to undertake this work on its own behalf. There was clear evidence that both Coral and later, Union, made respective applications for leave to construct the gas connection. Coral abandoned its application once the contractual negotiation bore fruit in the form of an acceptable rate structure, codified in the Contract for Carriage. Union proceeded to construct the gas connection. This would support a finding that the negotiated rate was, if not necessarily a bypass competitive rate, at least was a rate which was attractive enough to quell any interest that Coral had in developing the gas connection on its own account.

The Contract for Carriage captured that rate structure, which, appears to have been predicated on a high, non-obligated DCQ, resulting in DCC rebates to support the net cost of gas supply.

Prior to the execution of the Contract for Carriage, Coral could have, and perhaps should have, made application to the Board for a bypass competitive rate to govern gas supply for Brighton Beach. Instead, it entered into the Contract for Carriage and accepted the rate structures and contingencies associated with it.

The next step in the process involved the realization that the DCC itself, with the full endorsement of all parties in the Union rate proceedings, including Union itself, was to be eliminated. The specific scope and manner of its elimination had not been agreed upon. Union had made a proposal for its elimination, which had not been unreservedly endorsed by all interested parties. Coral's response to this development was to secure the Clarification Agreement, which, inter alia, provided for the "best efforts" clause referred to above.

Union advanced its original proposal for the elimination of the DCC in RP-2001-0019. Coral did not intervene in that case. Its sole engagement in the regulatory process respecting the issue was to file a single letter of comment urging the Board to implement Union’ s proposal for DCC elimination.

When the DCC was eliminated by the Board’s decision in that case on a basis that did not entrench the DCC rebate into the respective direct purchase rate classes, Coral then directed Union to fulfill its obligation under the "best efforts" clause of the Clarification Agreement. Union stated that it has done so.

Having voluntarily organized its relationship with Union through contract, it is not now reasonable for Coral to insist upon the imposition by the Board of a bypass-competitive rate when the circumstances first underlying, then undermining the contractual arrangement have themselves been anticipated and addressed in contract.

It is conceivable that under some circumstances where the relative positions of the parties was different, or where a customer of the utility has been clearly overwhelmed by the resources and expertise of the Utility, that the Board could impose a rate solution, notwithstanding the existence of a binding contract between the parties. None of those circumstances are present here.

The Creation of a Unique Rate For Gas-Fueled Merchant Generation Plants

It is not surprising that Union has been unable to construct a post-DCC rate structure that offers anything like an equivalent financial prospect to Coral. The original rate structure captured in the Contract for Carriage was heavily dependent on the DCC rebates. Now that the DCC has been eliminated, there is, under existing rate structures, little scope for the creation of a similarly tuned rate.

Coral’s argument urges the Board to determine that the unique nature of the operation of the Brighton Beach facility, that was the profile of its gas usage, justifies the creation of a unique rate class. Coral goes on to say that there was an important issue of public policy which was engaged by its dilemma, and that the public interest in the development of new generation requires the establishment of a unique rate treatment for plants of this nature, including, if necessary, the creation of a so-called end use rate structure which would be applicable to any like operations, simply on the basis of their conformity with a stipulated business category. Union currently has no end-use rates in its array of rate structures, and such rates are a rarity in regulated markets.

Coral's argument is rooted in the fact that virtually all observers of the energy market in Ontario have identified a shortfall of generation supply as a key contributor to destabilizing concerns respecting the adequacy of supply for Ontario's current residential and industrial needs, creating an unwelcome dependence on out-of-province supply, which is a possible inhibitor of economic growth, and a contributor to significant price volatility.

Plants such as the Brighton Beach facility are designed to contribute significant levels of electricity to the IMO-administered grid at times when premium prices are available for incremental supply. Such plants are intended to operate only when the demand for electricity for the grid has created a price environment where a premium was paid for incremental supply. Such plants do not operate constantly, but intermittently, according to the demands and opportunities presented by the electricity market.

Natural gas-fueled generators are uniquely capable of responding to demand and price cues. Unlike other generation assets, they can move from inactivity to full contribution very rapidly. This usage profile also distinguishes them from other industrial customers. While most operations draw gas on a consistent and substantially predictable hour-over-hour basis, gas-fueled generation operations such as Brighton Beach are largely unpredictable, and move from zero usage for most of the time to full capacity draw over a short period, depending on electricity market price cues. A concern was expressed that conventional industrial users ought not to be required to pay more within the T1 rate class to accommodate a unique treatment for the gas-fueled generation operations.

The current rate class applicable to the Brighton Beach facility was T1. This rate applies to a very wide range of industrial users, with varying load profiles. Union's rate proposal invoked T1 rates applied in two blocks. This, Coral suggested, was a recognition by Union that the Brighton Beach profile was unique, and justified a very different rate treatment, outside of the normal restrictions imposed by the T1 rate rules.

The development and design of a rate or rate class is a process that is governed by principles which have been developed by scholars and practitioners. Principles are necessary because of the high degree of interdependence of gas distribution system participants. Of all the principles governing the establishment of rates and rate classes, the most fundamental is that requiring that rate classes should be responsible for a reasonable proportion of the costs they cause the system to incur.

The revenue requirement established by the Board in rates cases such as the present case represents the system's overall financial burden. In order for rates to be just and reasonable, which is the statutory requirement, each rate class should bear a proportion of that burden roughly coincident with the costs incurred by the system operator, in this case Union Gas, in providing the necessary infrastructure and services to arrange for, store and transport the commodity to that rate class' members. Where a disproportionate amount of the revenue requirement is visited upon a rate class, that rate class is either subsidizing or being subsidized by other system participants. Rates are developed to avoid any such disproportionality to the extent reasonably possible. For this reason, so-called end-use rates have not been a common feature of regulated markets. In order to ensure that the appropriate cost causation allocation is made respecting a specific category of user, the regulator must first establish the demands placed upon the system by the consumer arising from the consumer's usage profile, not the category of its business undertaking. It is also important to note that there may be important sub-categories of generation end-users. Co-generation plants for example, where the plant produces steam for industrial users as well as electricity, have markedly different operational considerations, compared to pure merchant operations, such as the one at Brighton Beach.

A number of parties in this proceeding urged the Board to avoid making a decision on the fundamental issue of rate design for gas-fueled generators, on the grounds that the manner in which the issue was presented, and its timing within the proceeding, meant that there has been an insufficient opportunity for a thorough presentation and examination of the very complex and important private and public issues raised by Coral's intervention.

The Board considers that the important public interest issues invoked by the Coral intervention are of such a nature that they warrant a more expansive opportunity for presentation and examination of detailed evidence regarding the specific load profile presented by the Brighton Beach facility and other like or similar operations. The public interest consists in large part of the perceived requirement for additional electricity generation in Ontario. This aspect alone distinguishes this case from typical gas rate applications, where the interests which dominate the proceeding typically involve a private contest between the monopolist utility and its customers. Further, the Board does not have sufficient evidence before it now to assess the extent to which this load profile justifies, on the basis of generally accepted rate design principles, a unique rate class for such undertakings, nor the implications such an approach may have for members of the current T1 rate class, or other rate classes. In addition, the Board considers that it does not have sufficient material before it with respect to the consideration of so-called end user rates.

The public interest in the matter carries a measure of urgency. The development of new generation assets has been identified as a high priority for the government in an environment that has been characterized as being short of electricity supply. Coral, too, is facing pressures respecting the commissioning of the Brighton Beach facility.

Accordingly, pursuant to Section 21, of the Act, the Board directs Union to begin immediately to prepare and submit detailed evidence respecting the reasonably anticipated load profile associated with the Brighton Beach facility, based on the extrapolation of available data, in consultation with Coral and other interested parties. It is the Board's expectation that Union will use the cost allocation methodology approved in EBRO 499. Union should determine if there is a basis, consistent with applicable ratemaking principles, for establishing a new rate class for customers with Coral's load profile and if so, apply for Board approval. Union shall do this by no later than August 1, 2004. The procedure timeline to be followed will be established in a Procedural Order, which will include provision for late intervention requests by interested parties who are not currently intervenors.

Notwithstanding this unresolved issue, the Board intends to finalize rates for 2004 as soon as possible. If there is a basis for establishing a new rate class, that will be implemented on a prospective basis, no earlier than as part of the 2005 rates. While the issue is important and should be addressed as soon as possible, the Board notes that the DCC is still being phased out and a significant portion of it continues to be available to Coral for 2004. Furthermore, as Coral advised, gas distribution costs only represent approximately one percent of Coral's anticipated operating costs.

10. DEFERRAL ACCOUNTS

There are three categories of deferral accounts, namely, the Gas Supply-Related Accounts, the Storage and Transportation-Related Accounts and Other Deferral Accounts.

10.1 PROPOSED CHANGES TO GAS DEFERRAL ACCOUNTS

New Deferral Accounts

Union proposed to establish the following new deferral accounts:

1. North Purchase Gas Variance Account (179-105)
2. South Purchase Gas Variance Account (179-106)
3. Spot Gas Variance Account (179- 107)
4. Unabsorbed Demand Cost (UDC) Variance Account (179-108)
5. Inventory Revaluation Account (179-109)

10.2 PROPOSED ACCOUNT CLOSURES

Union proposed to close the following deferral accounts:

1. Firm Supply Purchase Gas Variance Account (“PGVA”) (179-80)

2. Other Purchased Gas Costs Account (179-68)

3. TCPL tolls & Fuels - Southern Operations Area (179-67)

4. Incremental Unbundling Costs (179-101)

5. Pipeline Integrity (179-104)

The Board approved the proposed new deferral accounts in its Accounting Orders, RP-2003-063/EB-2003-0087/EB-2003-0097, dated November 19, 2003. The Board also approved the closure of deferral accounts 179-80, 179-68 and 179-67.

10.3 PROPOSED CHANGES TO OTHER DEFERRAL ACCOUNTS

New Account - Gas Distribution Access Rule (GDAR) Deferral Account

Union proposed to create a new account to capture the difference between the forecasted incremental cost to implement the appropriate process and system changes to comply with GDAR and the actual costs incurred. Union estimated that it would incur capital costs of $4.78 million and operating and maintenance expenses of $1.3 million.

Lost Revenue Adjustment Mechanism Deferral Account (179-75)

Union proposed to modify the calculation of the amounts recorded in this account, which was originally established in E.B.R.O. 499 to record any margin variances resulting from the impact of the energy savings realized from Union's DSM programs. The Board approved the continuation of this account in its RP-1999-0017 Decision.

Union proposed to build the 2004 target into its demand forecast for 2004. Upon the completion of the 2004 plan year, Union will evaluate the results and a true-up will be recorded in the LRAM deferral account for variances in the number of program participants.

Storage and Transportation Related Deferral Accounts: Combination of Balancing Service Deferral Account (179-70) and Short- term Storage Services account (179-71)

Union requested approval to combine the Balancing Service Deferral Account (179-70) and Short- term Storage Services account (179-71) into one account. Union proposed to close account 179-71 and expand the scope of account 179-70 to include the net revenue generated from the short-term storage services account (179-71). The services deferred in the existing 179-70 and 179-71 accounts were similar in nature. Balancing services were provided through a combination of storage and loans depending upon the availability of the assets. The disposition of each of these deferral accounts was based on the same allocation methodology. As such, combining these accounts would have no impact on the allocation of account balances to customers.

The following storage and transportation related accounts remain unchanged.

Transportation and exchange deferral account (179-69);

Long-term peak storage deferral account (179-72);

Miscellaneous S&T deferral account (179-73); and

Other Direct Purchase Services deferral account (179-74).

The pipeline integrity account was established in RP-2001-0029 to record the incremental cost incurred by Union to meet new provincial pipeline integrity regulations. Union's cost of service forecast for 2004 includes costs associated with meeting the guidelines established by the new regulations. The projected balance as of December 31, 2003 is $3.358 million. Union requested that the Board approve closure of this deferral account following the disposition of the 2003 deferral account balance.

10.4 DISPOSITION OF THE 2003 DEFERRAL ACCOUNT BALANCES

Gas Supply Related Deferral Accounts

Firm Supply Purchase Gas Variance Deferral Account (179-80)

Union proposed to allocate the 2003 balance, net of deferral recovery adjustments to firm rate classes in the Northern and Eastern Operations Area, and all rate classes in the Southern Operations Area, in proportion to system sales volume in 2002.

Other Purchased Gas Costs Deferral Account ("OPGCA") (179-68)

Load Balancing

According to Union, as of December 31, 2003, the projected load balancing account was $44.837 million. In EB-2003-0056, the Board approved the prospective recovery of these costs, net of amounts recovered in rates. Union proposed to recover $36.036 million, net of deferral recovery adjustments from sales service and direct purchase customers in the Southern Operations area and $8.801 million, net of deferral recovery adjustments from sales service and direct purchase customers in the Northern and Eastern Operations area.

The allocation of the load balancing related costs to individual rate classes was based on the March 31 imbalances for each rate class. Union will ensure that summer peaking and higher base load customers will only pay the appropriate share of the increased gas costs attributable to the increased winter demand.

Flexibility

According to Union, as of December 31, 2003, the projected Flexibility - South account was $61.227 million. Flexibility-related costs in the OPGCA represent the difference between the landed costs of all non-TCPL supplies and the Ontario Landed Reference Price, net of any Load Balancing costs.

In EB-2003-0056, the Board approved recovery from all general service customers in the Southern Operations area and Northern and Eastern Operations area. Union is now proposing to recover $61.227 million, net of deferral recovery adjustments from sales service and direct purchase customers in the Southern Operations area. Union will ensure that summer peaking and higher base load customers will only pay the appropriate share of the increased gas costs attributable to the increased winter demand.

Inventory Revaluation

According to Union, as of December 31, 2003, the projected inventory revaluation account was a credit balance of $15.707 million. The allocation of Inventory Revaluation in the South will be to all rate classes in proportion to 2003 system sales volume in the Southern Operations Area. In the North, allocation will be to rate classes in proportion to firm 2003 system sales volume in the Northern and Eastern Operations Area.

10.5 SOUTHERN OPERATIONS AREA GAS SUPPLY-RELATED DEFERRAL ACCOUNTS

TCPL Tolls and Fuel (179-67)

Union proposed to allocate the 2003 balance to all rate classes in the Southern Operations area in proportion to 2003 sales service volume.

10.6 NORTHERN AND EASTERN OPERATIONS AREA GAS SUPPLY-RELATED DEFERRAL ACCOUNTS

Heating Value Deferral Account (179-89)

The balance will be allocated to the Rate 01 and Rate 10 classes in proportion to firm 2003 system sales, ABC-T and bundled-T delivery volume for those rate classes.

TCPL Tolls and Fuel Deferral Account (179-100)

Tolls, Load Balancing Account, Capacity Assignments

Union proposed to allocate the net balance to rate classes in the Northern and Eastern Operations area in proportion to the firm 2003 sales service, ABC-T and Bundled-T delivery volumes.

Fuel

Union proposed to allocate the compressor fuel component, net of prospective recovered revenue, to rate classes in proportion to firm 2003 sales service volumes in the Northern and Eastern Operations area.

10.7 2003 STORAGE AND TRANSPORTATION RELATED DEFERRAL ACCOUNTS

Transportation and Exchange Services (179-69)

Union proposed to allocate the balance to firm C1 and M12 customers and in-franchise customers in proportion to actual 2003 available capacity. Further, Union proposed to allocate the balance allocated to in-franchise customers in the Southern Operations Area to rate classes in proportion to E.B.R.O. 499 design peak day demand. Finally, Union proposed to allocate the balance to customers in the Northern and Eastern Operations Area, by virtue of their use of transportation systems in the Southern Operations Area, to rate classes in proportion to the allocation of 1999 storage demand costs as approved in E.B.R.O. 499.

Short-term Storage and other Balancing Services Deferral Account (179-70/71)

Union proposed to allocate the 2003 balance related to off-peak storage between in-franchise and ex-franchise customers, including customers in the Northern and Eastern Operations Area, in proportion to the allocation of peak storage, as approved in rates. Union proposed to allocate the amount related to C1 firm short-term deliverability between in-franchise and ex-franchise customers in proportion to the allocation of the 1999 storage deliverability. Consistent with the approach outlined in RP-2001- 0029, Union proposed to recover $60,000 in forecast Load Balancing Account charges that were credited to EGDI in 2003. Union proposed that the balance related to in-franchise customers in the Southern Operations Area be allocated among rate classes in proportion to E.B.R.O. 499 design peak day demand and the balance related to in-franchise customers in the Northern and Eastern Operations Area, by virtue of their use of storage in the Southern Operations Area, be allocated among rate classes in proportion to the allocation of 1999 storage demand costs, as approved in E.B.R.O. 499.

Long-Term Peak Storage Services Deferral Account (179-72), Other S&T Services Deferral Account (179-73) and Other Purchase Services Deferral Account (179-74)

Union proposed to allocate the aggregate 2003 balance to in-franchise rate classes in the Southern Operations Area in proportion to E.B.R.O. 499 design peak day demand and in-franchise rate classes in the Northern and Eastern Operations Area, by virtue of their use of storage in the Southern Operations Area, in proportion to the allocation of 1999 storage demand costs, as approved in E.B.R.O. 499.

10.8 ALLOCATION OF OTHER DEFERRAL ACCOUNTS

Deferred Customer Rebates/Charges Deferral Account (179-26)

Union proposed to allocate the balance to rate classes in proportion to the 1999 Board- approved number of General Service customers in the Northern and Eastern Operations and Southern Operations area.

Comprehensive Customer Information Program Deferral Account (179-56)

Union proposed to allocate the balance to rate classes in proportion to the 1999 Board-approved weighted-average number of small volume consumers in the Northern and Eastern Operations and Southern Operations area, as approved in RP-2000-0078.

Direct Purchase Revenue and Payments Deferral Account (179-60)

Union proposed to allocate the balance to rate classes in the Southern Operations Area in proportion to E.B.R.O. 499 Dawn-Trafalgar design day demand. This allocation was the same as that used to allocate the amount approved in rates.

Lost Revenue Adjustment Mechanism (“LRAM”) Deferral Account (179-75)

Union proposed to allocate the 2003 balance to in-franchise customers in proportion to the margin reduction attributable to DSM activities.

Incremental Unbundling Costs Deferral Account (179-101)

There was no allocation required as the balance was zero.

Intra-period WACOG Deferral Account (179-102)

Union proposed to allocate the 2003 balance to rate classes in proportion to the allocation of the pass-through items that the intra-period WACOG charge relates to.

Unbundled Services Unauthorized Storage Overrun Deferral Account (179-103)

There was no allocation required as the balance was zero.

Pipeline Integrity Deferral Account (179-104)

Union proposed to allocate the balance to rate classes in proportion to 1999 total other transmission demand-related costs in the Southern Operations Area and in proportion to 1999 total distribution-related costs in the Northern and Eastern Operations Area as was approved for the 2002 balance in the account.

Union's Reply Argument

Union noted that no intervenor had commented on the 2003 year end Non-Gas Cost Deferral Account balances and submitted that these balances should be disposed of as requested. However, LPMA submitted that there should be a deferral account to record the gains from the disposition of any non-depreciable assets. LPMA also submitted that an interest rate of 4.15% is excessive and should be reduced to 3.3%. LPMA also suggests quarterly adjustment of interest rates for all deferral accounts.

Board Findings

At the request of Union and with the consent of all parties, the Board issued an accounting order on November 19th 2003 approving Union's proposals for restructuring the gas supply deferral accounts.

No parties argued against the proposed disposition of the deferral accounts and the Board finds the methodology adopted by Union to be reasonable. The Board approves the proposed disposition methodology for the deferral accounts.

The Board's findings respecting the S&T deferral account (Chapter 4.4) and the proposed GDAR deferral account (Chapter 2.4) appear elsewhere in this Decision.

The Board will allow the disposition of the balance of $3.358 million in the IMP deferral account (account 179-Y1) as of December 31, 2003, subject to true-up of this balance. Deferral account 179-Y1 shall then be closed.

The final balances to be disposed of in connection with the respective deferral accounts will be established by the Board after reviewing Union's working documents, which will be submitted in support of its draft rate order.

The Board rejects the intervenor proposal to set up a deferral account to record the gains from dispositions of assets. The Board directs Union to track such dispositions within its accounting system under generally accepted accounting principles. At the time of the next rate proceeding the Board will consider the appropriate allocation of proceeds of such dispositions between the shareholder and the ratepayer.

The Board defers further consideration of the intervenor proposal to adjust the interest rate applied to deferral account balances on a quarterly basis. The Board directs Union to provide an assessment of this proposal at the time of its next rate application.

11. DEMAND SIDE MANAGEMENT

Background

Union stated that it is currently undertaking DSM within an approved plan framework that expires at the end of 2004. Union further stated that in this context its evidence in this proceeding had three purposes:

1. describe Union's current approach;
2. respond to concerns raised by the Board regarding DSM; and,
3. propose a new approach for conducting DSM in 2004 and beyond.

To achieve these purposes, Union filed evidence on a proposed new DSM process, a proposed 2004 DSM savings volume target, the 2004 DSM budget, the Lost Revenue Adjustment Mechanism ("LRAM") levels and approach, and the audit process. There were two other DSM issues included on the Issues List. The first was a DSM variance account for DSM O&M expenditures. The second, which was included as a placeholder, was the pilot shareholder incentive for DSM programs.

The Board had accepted the LRAM as part of a settlement agreement in EBRO 499. Union's evidence in this proceeding described the LRAM as a deferral mechanism that allows Union to recover revenues lost as a result of reductions in customers' natural gas consumption caused by the influence of Union's DSM programs. The lost revenues are recorded in the LRAM deferral account, and after review by the

Board, approved LRAM deferral account balances are recovered from Union's customers.

The Settlement Conference held as part of this proceeding resulted in a settlement of almost all of the DSM issues. All of the parties with the exception of Pollution Probe agreed to a settlement of DSM issues. The Settlement Agreement, attached as Appendix A to this decision, outlines the terms of this settlement. Pollution Probe, while adopting the settlement for most of the DSM related issues, did not accept the settlement of the issues described below:

- the direct DSM expenditure budget for 2004 was set at $4 million, representing an increase of $1.25 million over the amount included in Union's evidence. The larger budget was required to pursue a greater level of savings and to conduct the research outlined in the Settlement Agreement. The amount to be spent on this research was not to exceed $250,000.

- the 2004 DSM target was to be increased from the level included in Union's evidence of 41 million m^3 to 62 million m^3. It was also agreed that the 2004 target would be further adjusted for the impact of any changes in assumptions resulting from the 2002 LRAM evaluation process, except for the adjustment to reflect a 30% free rider rate on custom projects, which is already reflected in the 62 million m^3 target.

In its update, filed in October 2003, Union stated that the above referenced changes in assumptions resulting from the 2002 LRAM evaluation process caused a reduction of 3.9 $10^6 m^3$ to the agreed 62 million m^3 target. Consequentially, the 2004 DSM target savings became 58.1 million m^3.

Position of the Parties

Pollution Probe, while in partial support of the Settlement Agreement, took the position that Union's target volume was too low relative to the comparable target parameters of EGDI, and argued that the Board should therefore increase Union's

2004 DSM budget from \$4.0 million to \$10.0 million and direct Union to make a best efforts attempt to achieve an annual volume saving of 85.8 10^6m^3 by 2005 or sooner.

Union's Position

Union stated that the target of 85.8 10^6m^3 proposed by Pollution Probe was unrealistic.

Union noted that the GEC witness called by Pollution Probe could not confirm that the higher DSM targets sought by Pollution Probe were achievable. Mr. Neme's own evidence had recommended a target volume of 60.0 10^6m^3 which is very similar to the volume of 58.1 10^6m^3 contained in the Settlement Agreement.

Union contended that the argument of Pollution Probe was not based upon the evidence. Instead, Pollution Probe made a number of performance comparisons with EGDI, which indicated that the unit cost of the volumetric savings forecast to be achieved by Union is lower than that of EGDI. Union suggested that this may be a reflection of structural differences between the respective markets and customer bases of the two utilities.

Union submitted that the Board should reconfirm the Settlement Agreement and reject the arguments of Pollution Probe.

Board Findings

The Board approves the DSM budget and target volume for fiscal 2004, as outlined in the Settlement Agreement. The Board does not consider that sufficient evidence was presented by Pollution Probe that the incremental increase in Union's DSM budget, which it proposed, would result in the target volume it sought being reasonably attainable. Indeed, the evidence of Mr. Neme suggested that the targets reflected in the Settlement Agreement were appropriate, and that an increase in the DSM budget could not be assumed to result in the reduction sought by Pollution Probe. The Board is mindful of the importance of conservation activities, and the need to encourage and support them. However, there is no virtue in developing targets and imposing requirements which are not supported by the evidence, or which appear to be unattainable. The Board also notes that Pollution Probe's proposed budget and target far exceeded the consensus prevailing among the other parties.

12. RATE IMPLEMENTATION

Based upon Union's current 2003 rates, the Board has found a total revenue sufficiency for Union's combined delivery and gas supply related functions of $85.652 million for 2004, based upon an overall rate of return of 8.72% and a Board approved rate base of $3,071.1 million. The Board estimates that $80.787 million of the total sufficiency is associated with Union's gas supply function, which includes gas supply administrative recovery of $5.56 million. The corresponding delivery related sufficiency is therefore $4.865 million. The rebate of this sufficiency will result in an overall rate decrease of approximately 0.30 percent, although the impact will vary by customer class. Union is directed to reduce its rates for 2004 to annul the sufficiency of $4.865 million.

Union is directed to prepare a draft rate order giving effect to this Decision, with the appropriate rate adjustments, to be filed with the Board Secretary and submitted to intervenors no later than Friday April 16, 2004. Intervenors will have until Friday, April 23 to file comments with the Board. The Board will issue the final rate order no later than Friday, April 30, 2004.

The Board expects Union to commence implementation of the new 2004 rates upon its May, 2004 billing cycle. Should Union choose to implement the new rates at a later date, it is directed not to accrue any further interest on the outstanding deferral account balances to be cleared by authority of this Decision, beyond April 30, 2004. The effective date of the new rates is January 1, 2004.

Should Union decide to delay implementation of the new rates, the Board directs that Union's customer information notices make clear that no interest has accrued to the deferral account balances beyond April 30, 2004.

The Board was assisted in the course of the hearing by the intervenors, many of whom have made cost submissions. The Board will issue a cost award decision shortly, identifying the percentage recovery established for each intervenor requesting costs.

The Board's costs of the proceeding shall be paid by Union upon receipt of the Board's invoice.

DATED at Toronto, March 18, 2004.

Paul B. Sommerville
Presiding Member

Art Birchenough
Member