METHODOLOGIES FOR COMMODITY PRICING, LOAD BALANCING AND COST ALLOCATION FOR NATURAL GAS DISTRIBUTORS

Background and Overview

1. The Ontario Energy Board ("the Board") initiated the Natural Gas Forum ("NGF") in 2003 to review the policies and processes underlying key structural components of the natural gas regulatory system. After comprehensive discussions with ratepayers, retailers and utilities, the Board determined that the stakeholders were largely satisfied with the existing regulatory system and that the natural gas sector would benefit more from specific improvements than from a transformative change.

2. Accordingly, the subsequent consultation focused on three broad areas of gas regulation: rate regulation, storage and transportation, and regulated gas supply. The Board set direction and drew many conclusions in its NGF report titled "Natural Gas Regulation in Ontario: A Renewed Policy Framework", issued on March 30, 2005.

3. With respect to regulated gas supply, the Board concluded that utilities should continue to provide a regulated gas supply option. The Board indicated the importance of consumer choice in a transparent market, where customers understand their options and manage their risks, including price volatility.

4. In reaching this finding, the Board determined a further review was needed in three specific areas of regulated gas supply. On May 29, 2008, the Board commenced a proceeding on its own motion to consider the methodologies to be used by gas utilities for:
   a) gas commodity pricing;
   b) load balancing; and

c) cost allocation between the supply and delivery functions in relation to regulated gas supply.

5. Subsequently, on August 8, 2008 the Board issued a Decision and Order regarding the issues to be considered in this proceeding. This evidence of Enbridge Gas Distribution ("Enbridge", "EGD" or "the Company") responds to those issues.

Current Experience

6. The Quarterly Rate Adjustment Mechanism ("QRAM") process for Enbridge was originally approved on May 30, 2001 as part of RP-2000-0040 and subsequently modified in RP-2002-0133 and RP-2003-0203. The parties established the QRAM process to achieve an enhanced reflection of gas supply prices on a regular basis while mitigating large annual adjustments to customer bills.

7. The RP-2000-0040 Decision and associated Settlement Agreement are instructive for a number of reasons. They show that the parties put much care and attention into developing the most appropriate QRAM process for Enbridge. In its Decision, the Board endorsed the principles and the process set out in the Settlement Agreement.

8. The QRAM process approved by the Board for Enbridge consists of the following four components:

- <u>Determination of the QRAM Reference Price</u>
  This component includes the calculation of a forecast reference price or ("utility price") for rate-making purposes and the means of adjusting the reference price and the Company's rates on a quarterly basis.

- Purchased Gas Variance Account ("PGVA")

  This element provides the means of tracking and clearing variances between the forecast cost of gas and the actual cost of gas. These variances are recorded in Enbridge's PGVA and ensure ratepayers and the Company are held whole with respect to gas costs.

- QRAM Approval Process

  The regulatory framework provides for Board approval of the forecast reference price, rate changes and PGVA clearances / adjustments.

- Customer Communication

  This component disseminates rate information and associated impacts to end-use customers, marketers, and other stakeholders.

9. In its QRAM applications Enbridge lays out in a transparent manner the determination of the forecast reference price and then derives its effect on all gas supply related costs such as gas costs, carrying costs of gas in storage, working cash allowance (gas costs), and unbilled and unaccounted for gas.

10. Enbridge then uses the newly determined forecast reference price as the basis for adjusting the annualized revenue requirement. Next, Enbridge adjusts its gas supply charges for sales service and delivery charges for all customers. The new reference price is also used as a benchmark for PGVA purposes. In other words, if Enbridge's forecast gas supply costs collected in rates are over or under its actual costs, the difference is recorded in the PGVA. The Company then reimburses or collects the difference from customers through PGVA adjustments (which are referred to on customer bills as gas cost adjustments).

11. The QRAM process includes the regulatory framework for interested parties and the Board to review Enbridge's QRAM applications. Thereafter, the Board issues

an order disposing of the application in time for the Company to implement the resultant rates during the first billing cycle of the next quarter.

12. Enbridge informs all customers of QRAM rate changes and/or PGVA adjustments by means of bill inserts (i.e., customer rate notices) as well as by posting the same information on its website. As part of the QRAM process, Enbridge's rate notices are reviewed and approved by the Board.

13. It is important to emphasize that Enbridge's QRAM process solely captures impacts stemming from changes in its forecast of gas costs. The Company's gas supply portfolio, volumes budget and any cost allocation or rate design changes / proposals are approved by the Board in its annual rates adjustment proceedings.

Enbridge's Evidence and Proposals in this Proceeding

14. Enbridge's objectives in the development of the pre-filed evidence are:
    - to describe how its current methodology works and to set out reasons for the different elements of the methodology;
    - to respond to the issues and make certain proposals while carefully considering potential impacts on ratepayers, gas retailers and utilities; and
    - to address standardization of the QRAM process.

15. In responding to the issues in this proceeding, Enbridge recognizes that the Board initiated this generic proceeding with a view that a higher level of standardization among Ontario natural gas utilities with respect to the QRAM process is desirable.

16. Based on the feedback at the Issues Conference the Board re-framed the issues, so they no longer presume standardization as the outcome. However, a higher degree of standardization of the QRAM process remains the Board's stated policy as per the Board Decision and Order from August 8, 2008 (p. 7, para. b) Board Findings.

17. The Company agrees that a higher degree of standardization as long as the methodology chosen is the most appropriate approach for each utility and the cost and complexity of standardization does not outweigh the potential benefits. In the Company's view some differences in the processes for the different utilities will need to be accommodated where operational differences force methodology variations and/or where the cost of standardization would surpass potential benefits.

18. Enbridge has worked with Union Gas to identify / determine areas where the utilities' current methodologies are:

- already standardized;
- different, and where standardization is appropriate (in such a case one of the utilities is proposing to adopt the methodology of the other); and
- different, but where standardization is not appropriate because of operational differences and/or other implications on ratepayers, retailers or utilities.

19. Enbridge and Union Gas have jointly developed the attached Appendix to provide a snapshot of their methodologies, current and proposed, as they apply to each issue in this proceeding.

20. The utilities consider certain elements of the QRAM process to be harmonized when they are fundamentally similar in the approach, principles used, and outcome.

21. Enbridge is proposing a number of changes to its QRAM methodology. The proposed changes will:

- increase the degree of harmonization between Enbridge and Union Gas;

- make Enbridge's QRAM process more mechanistic through changes such as proposed clearing of PGVA balances through a 12 month rolling rider; and
- provide benefits to all parties through a more streamlined QRAM process and through specific changes such as the proposed shortening of the time gap from 45 days to 30 days between the time forecast of gas costs is prepared and the QRAM effective date (which will serve to reduce PGVA balances) or such as the proposed adoption of the Mean Daily Volume ("MDV") reestablishment (which will serve to reduce pool Banked Gas Account ("BGA") balances).

22. Enbridge's proposals enhance the simplicity and efficiency of the QRAM process and continue to ensure ratepayers and the Company are held whole with respect to gas costs.

23. Lastly, the implementation costs stemming from this proceeding should be recovered by means of a deferral account. This approach is compatible with the Board's previous decisions on issues or matters that are Board-initiated or market enabling.

24. A glossary of terms is attached which provides definitions to terms used throughout the evidence.

Issue A. REVIEW AND STANDARDIZATION OF QUARTERLY RATE ADJUSTMENT MECHANISM ("QRAM") FOR ALL NATURAL GAS DISTRIBUTORS

Issue 1 Trigger mechanism for changing the reference price or clearing the purchased gas variance account ("PGVA")

Issue 1.1 Should there be a trigger mechanism to prompt a change in the reference price or to clear the PGVA?

25. EGD recommends that trigger mechanisms for changing the Reference price and clearing the PGVA are not required. The rationale is discussed below.

26. EGD's current QRAM methodology allows for two trigger mechanisms:
- Change in reference price: A price change is triggered in any quarter if there is a $0.005/m^3 change in the reference price for EGD.
- Change in Rider: A change in Rider C is triggered in any quarter if there is a $0.005/m^3 change in the projected Rider C unit rate, where the Rider is calculated as the projected PGVA balance divided by budgeted sales volumes for the remainder of the year.

27. When the QRAM methodology was implemented in 2002, the rationale for the trigger was to allow regulatory efficiencies and some level of rate stability. However, since its inception on January 1, 2002 there have only been three times when EGD did not request a change to the reference prices and in each instance the Company pierced the threshold for the Rider. There were also five instances when there was no Rider and the Company pierced the threshold for the reference price. From a Distributor perspective there is no administrative advantage or disadvantage of the trigger mechanism because in either situation all the necessary calculations must be performed.

28. The current QRAM methodologies for Union and Enbridge while similar in other areas (i.e., 21-day forecast of market prices, 12 month forecast period) are not

harmonized with respect to the trigger. Union implements a change to its reference price and Rider every quarter irrespective of the level of the change. Customers have become conditioned to a quarterly rate change and as previously stated, EGD has operated virtually as if there was no trigger mechanism. Therefore, there are no advantages/disadvantages to the utility or negative implications on customers from removing the trigger mechanism. Eliminating the trigger mechanism at EGD would increase QRAM harmonization between EGD and Union.

Issue 1.2 If a trigger mechanism is desirable, what methodology or methodologies should be used by all natural gas distributors for setting the trigger to prompt a change in the reference price or to clear the PGVA?

29. A trigger mechanism is no longer required.

Issue 2 Price adjustment frequency and forecast periods.

Issue 2.1 Is a price adjustment based on a 12-month price forecast appropriate for the regulated gas supply option?

30. A price adjustment based on a 12 month price forecast is appropriate for the regulated gas supply option and is harmonized between Union Gas and EGD. The rationale for the 12 month price forecast stems directly from the regulatory principles and processes underpinning the LDC's gas supply option, as follows:

- LDC's are required to pass on the true cost of gas supply to their customers.
- This is achieved through a forecast of price followed by a true up of the forecast price with the actual price.
- The forecasting methodology must reflect the operational reality of how gas costs are incurred.
- Failure to link forecasting methodology with cost incurrence will result in greater variances which must be trued up at a later date.

31. The 12 month price forecast reflects the manner in which EGD incurs its gas supply costs. Unlike Albertans, who live in close proximity to a supply basin, Ontarians rely on long haul transportation to move gas to the province. The close proximity of storage to the Ontario market, however, allows EGD to use long haul transport at a 100% load factor and store excess supplies in the summer for withdrawal in the winter. This means that gas purchased in a particular month or quarter may not be consumed in the same month or quarter, however, over a twelve month period the quantity of gas purchased and sold is equal. Since purchase prices vary between months/quarters, applying a price based on a twelve month average to varying monthly consumption would result in annual billings being equal to annual purchases, assuming that there is no variance between forecast and actual prices. This is how the current methodology works. However, under an alternative methodology such as a monthly forecast, applying a varying monthly price to varying monthly consumption would result in a variance between annual billings and annual purchases even if there is no variance between forecast and actual prices. Such a pricing methodology is inherently flawed, because if prices are set under perfect certainty there should be no variances or true ups. Adopting a methodology that is inherently flawed would result in poor pricing signals and customer confusion. This is shown in the table below.

	Delivery - m*3 (Col. 1)	Monthly Market Price (Col. 2)	Assumed Acquisition Cost (Col. 3) (Col. 1 x Col.2)	Consumption - m*3 (Col. 4)	Monthly Bill @ 12 month price (Col. 5) (Col. 4 x Note 1)	Monthly Bill @ monthly price (Col. 6) (Col. 4 x Col.2)
October	300	0.374	112.14	192	70.57	71.64
November	300	0.382	114.58	333	122.53	127.08
December	300	0.393	117.81	534	196.56	209.60
January	300	0.400	120.11	644	237.26	257.94
February	300	0.398	119.34	555	204.35	220.76
March	300	0.391	117.45	483	177.94	189.18
April	300	0.329	98.69	307	113.00	100.95
May	300	0.323	96.77	166	61.05	53.47
June	300	0.325	97.39	115	42.43	37.40
July	300	0.366	109.67	87	32.04	31.80
August	300	0.368	110.54	83	30.74	30.76
September	300	0.371	111.22	101	37.23	37.49
	3,600		1,325.71	3,600	1,325.71	1,368.07
Note 1 - Gas Supply Charge			0.368			
Variance in PGVA if monthly market price is used						42.36

32. As illustrated in the table above, the use of a 12 month average price (Gas Supply Charge of 0.368 in Note 1) results in annual billings equal to annual acquisition cost ($1,325.71 in Col. 3 and Col. 5). Applying the monthly price to monthly volume results in an annual bill of $1,368.07 (Col. 6), which creates an excess billing of $42.36 (Col. 6 – Col. 3) which must be returned to the customer through an adjustment. This would occur even if forecast prices equal actual prices.

33. The 12 month price forecast period is also aligned with the operational requirements for the direct purchase customers who are required to deliver a mean daily volume throughout the year rather than a volume of gas equal to their daily consumption. A pricing signal that assumes that the distributor purchases the monthly requirements of sales customers on a monthly basis, for example, while direct purchase customers purchase their supply on a twelve month basis, creates inequity between the two offerings. In any event, the assumption that

monthly purchases equal monthly consumption for sales customers, when it is not true, must subsequently be reversed through a true up to actual purchasing patterns.

34. It is EGD's position, that the current methodology is internally consistent, equitable for sales and direct purchase customers and harmonized between Union and EGD.

Issue 2.2 If not, what alternative forecast period or periods should be used by natural gas distributors?

35. For the reasons outlined in response 2.1, the 12 month forecast period is still the most appropriate methodology for establishing the reference price for Ontario's gas distributors. It is not appropriate to adopt methodologies from other gas jurisdictions or retail electricity markets, unless similar operating processes and characteristics exist. For example, the default gas supply option in Alberta does not rely on a combination of long haul transport and storage to manage gas supply purchases. It is our understanding the default gas supply option in Manitoba and Quebec rely on the same tools as in Ontario. It is therefore not surprising that Manitoba, Quebec and Ontario utilities use a 12 month forecast period while Alberta has adopted a monthly price for its default supply option. Similarly, a monthly forecast may be appropriate for pricing default electricity supply, since electricity cannot be stored and must be generated and consumed at the same time.

Issue 2.3 Is a quarterly price adjustment appropriate for the regulated gas supply option?

36. Yes, a quarterly price adjustment based upon a 12 month forecast period is appropriate for the regulated gas supply option. An annual price change would be a return to the methodology prior to the implementation of QRAM's when price volatility was captured in the PGVA and cleared once a year. As discussed in

response 2.2, a monthly price adjustment based on a monthly forecast period would be inappropriate in Ontario because it would not capture the operating efficiencies that storage provides or the operating characteristics of the utility.

37. A monthly price change based upon a 12 month forecast period is used in Quebec. However, Gaz Metro's monthly price changes are completely mechanistic and only affect the commodity portion of the bill. Gaz Metro's rate design methodology allows for a three day turn around of their monthly rate setting mechanism, and is more of a notification than an approval process with their regulator. Also, it is EGD's understanding that all other cost changes are captured in deferral accounts and they have a year end rate base true up mechanism. This is different from EGD's process. Adopting the monthly price change would require significant changes to EGD's QRAM, cost allocation and rate design methodology, IT system billing and communication processes. This would result in significant regulatory and administrative costs to the ratepayers. EGD does not believe that the benefits of a monthly price change warrant the increased costs to ratepayers.

Issue 2.4 If not, what alternative frequency or frequencies should be used by natural gas distributors?

38. As previously stated, the Company believes that a 12 month forecast period is the appropriate mechanism.

Issue 3 Methodology for the calculation of the reference price.

Issue 3.1 Should a single Ontario-wide reference price be used as the basis for the gas supply commodity charge?

39. A single Ontario wide reference price (wholesale price) is used as the basis for the energy charge in Ontario's electric industry. However, the Ontario electricity industry also has a single system operator who is authorized to balance supply and demand for the entire province through appropriate purchases of electricity. Natural gas distributors in Ontario operate their distribution systems independently

of each other and use different purchasing strategies depending on their geographic location. To the extent that a single province wide price deviates from the distributor's operating and rate making practices, it would create dollar variances which must be trued up at a later date.

40. As noted in response 2.1, gas acquisition costs are treated as a pass through items to ratepayers. It follows therefore that the reference price should be based upon the supply portfolio of the distributor. The supply portfolio serves to meet the twin obligations of the distributor – supplier to sales customers and system operator for all customers on its system. Since the Ontario reference price reflects costs incurred for <u>both</u> these purposes, these costs must then be allocated based on Board approved principles to both sales and direct purchase customers. The calculation of the reference price and the cost allocation methodology is described below.

41. The supply portfolio is derived by forecasting the gas supply needs specific to EGD's sales customers, deliveries from direct purchase customers and the amount of gas supply required to balance forecast load on each day of the year. The gas supply portfolio cost is based upon a forecast of indices at the various supply basins/market hubs plus the associated transportation cost to deliver the gas to the franchise area. By doing so EGD develops a "Utility Price" or "Reference Price" of its forecasted acquisition cost including commodity, transportation and delivered supply costs. Once the forecast has been completed, Board approved cost allocation and rate design principles are used to allocate those costs between different types of service and rate classes, through the establishment of the gas supply charge, transportation charge, and load balancing charge. For example, the gas supply charge reflects the cost of procuring the commodity in the Alberta basin and applies only to sales customers. The transportation charge reflects the cost of transporting gas to the franchise area and applies to sales customers and to direct purchase customers who use EGD's

transport to bring gas to the franchise area. The load balancing charge captures the cost of daily load balancing and applies to all customers. All variances from the forecast costs are captured via the PGVA. The clearance of the PGVA to sales customers and direct purchase customers follows the same methodology that underpins the cost allocation and rate design.

42. It is unclear whether a single Ontario wide reference price refers to an “Alberta price” or a “Ontario landed price”. If the single Ontario reference price is Alberta based but inconsistent with the Company’s methodology, it would have cost allocation and price impacts on customers taking other types of service. If the single Ontario reference price is a landed cost in Ontario but does not reflect the cost of landing gas in the distributor’s franchise, it would vary from the portfolio cost, with implications for the PGVA and the allocation of costs to customers taking different types of service.

43. The ostensible purpose of having a single Ontario price is simplicity and transparency. However, the approach increases complexity because it is inconsistent with the regulatory principle of a pure cost pass through service. It is impossible for Union Gas and EGD to have identical gas supply portfolios because geography and physical connectivity affect gas supply portfolio composition. Using a price that is not determined from each distributor’s portfolio will result in greater price impacts on a deferred basis. As explained above, it could also violate the principle of using cost incurrence as the basis of pricing the gas supplier and system operator roles performed by the distributor. Thus, a single Ontario reference price would violate basic pricing principles such as minimizing retroactive adjustments and equity between service offerings, while increasing customer confusion.

Issue 3.2 If a single Ontario-wide reference price is implemented, how and by whom should it be determined?

44. As explained in 3.1 above, a single Ontario-wide reference price should not be implemented because it creates a disconnect between a distributor's procurement practice and pricing, with attendant impacts on equity between service offerings and retroactive billing.

Issue 3.3 If not, what supply units, pricing point data and method or methods should be used to determine the reference price?

45. The inputs should be reflective of the Utilities' 12 month supply portfolio and should be allocated in a manner consistent with each distributor's cost allocation and rate design methodology.

Issue 3.4 What role, if any, should the Board take in relation to the determination of the inputs and/or data to be used in calculating the reference price?

46. The Board should rely on the Distributor to prepare the calculation of the reference price. To assist the Board with its review of that calculation the Distributor could provide further detail should the Board see fit.

Issue 4 Deferral and variance accounts and disposition methodology

Issue 4.1 What should be the deferral/variance accounts to capture variances in commodity, transportation and load balancing and inventory revaluations?

47. EGD's PGVA account captures variances between actual gas acquisition costs and the forecasted costs underpinning the QRAM reference price. The intent of the variance account is to capture variances in costs that are outside the Distributor's control. The methodology to determine the deferral/variance account balances is directly linked to how they were captured in rates in the first place. Union and EGD's deferral accounts are harmonized in intent, though naming conventions, number of deferral accounts and the specific accounting entries may

vary. Subject to the discussion in 4.2, any harmonization for the number of deferral accounts and naming conventions is acceptable, as long as the composition of the deferral accounts and the methodology prescribed for the Distributors' accounting entries are consistent with its rate design methodology and its ratepayers and shareholders are held whole.

Issue 4.2 What methodology or methodologies should be used by natural gas distributors to determine the deferral/variance account balances to be disposed of?

48. As stated in the response to 4.1, the methodology to determine the deferral/variance account balance should be consistent with the rate design methodology of the respective distributor. However, there are some potential future implications due to a change in financial reporting standards which regulated entities will be required to adopt or follow commencing in 2011. The LDC's are currently involved in a Board initiated process which is attempting to determine the regulatory accounting requirements which the LDC's should follow as a result of a change in the accounting standards which they must report under. Currently, regulated entities follow Canadian Generally Accepted Accounting Policies with some allowed modifications coming from Generally Accepted Regulatory Principles. Commencing in 2011, these entities may be required to adopt and adhere to new principles and standards contained within International Financial Reporting Standards. The outcome of the Board process could have an impact on the balances and disposition within these deferral and variance accounts.

Issue 4.3 What methodology or methodologies should be used by natural gas distributors to dispose of the deferral/variance account balances? How frequently should the accounts be cleared?

49. As discussed in Issue 1.1, EGD currently follows a methodology whereby the projected year-end PGVA balance is forecast to be cleared by means of a Rider

each quarter. The rider is determined based upon the projected year end PGVA balance determined for the quarter divided by the budgeted sales volumes for the remainder of the year. For example, the first quarter rider is derived based on twelve months of forecast volume, the second quarter rider is derived based on nine months of forecast volume, etc. As a consequence, in periods of high volatility the Rider unit rate can fluctuate from quarter to quarter quite significantly especially if the volume base, for purposes of calculating the rider, is declining.

50. The projected December 31 PGVA balance includes actual and forecasted purchase costs (commodity, load balancing, and transportation) for each month of the fiscal year and compares that monthly price to the applicable QRAM reference price. This projected year end PGVA balance also includes amounts associated with inventory revaluations and current Rider C amounts. For purposes of calculating the Rider, EGD assumes all the price changes are attributable to commodity and therefore only collects or refunds the rider amounts to sales service customers.

51. At the end of the fiscal year, a true up exercise is performed in which the actual balances in the PGVA are allocated to the rate classes and type of service based on the specific components of the PGVA. This ensures that sales service and direct purchase customers participate towards the recovery or remittance of the costs which had accumulated in the PGVA.

52. This methodology is different than Union's. Union's methodology, as EGD understands it clears the previous three months balance accumulated in their PGVA and does not take into consideration any prospective year-end variances. The balance is cleared and unit rates are derived based upon a rolling 12 month forecast of volumes. Union's rider differentiates the costs attributable to sales service from the costs attributable to direct purchase and therefore their Rider's vary and are applicable to either sales or direct purchase customers. Further, the

Company understands that Union's method does not incorporate a year-end true up mechanism.

53. EGD is proposing to adopt and harmonize with Union's methodology as it relates to the determination of the PGVA amount to be cleared, the application of calculating the rider unit rates based upon the volumetric forecast for a 12 month period and the removal of a one time true up mechanism. EGD would propose to determine the PGVA actual balance amount based upon the prior three month PGVA balance and would determine the per unit rates based upon its 12 month Board approved volumetric forecast of volumes. Utilizing a 12 month forecast of volumes should serve to reduce the current volatility which currently exists in EGD's rider determination which is based upon the forecast consumption for the remainder of the year. In each quarter, EGD would identify the elements of its PGVA attributable to commodity, transportation and load balancing costs. Based on this breakdown, individual riders would be determined and applied to sales service, western bundled T-service and Ontario T-service customers. Developing a rider to reflect the manner in which costs are accumulated in the PGVA as they relate to commodity, transportation and load balancing would eliminate the need for the one time true up mechanism at year end.

Issue 4.4 Should there be a final adjustment to re-allocate the PGVA? What methodology or methodologies should be used for that purpose by natural gas distributors?

54. If the Board were to adopt the methodology discussed in response 4.3, EGD would propose implementing this new methodology January 1, 2010. EGD would also propose that the final balance in the 2009 PGVA would be subject to a one time final adjustment in order to begin the 2010 year with a projected zero balance. With the implementation of the proposed methodology discussed in response to 4.3, there would be no further need to a final adjustment to the PGVA at year end.

Issue 4.5 What are the implications of the different methodologies considered in light of seasonal consumption patterns?

55. Response to question 4.3 outlines the two different methodologies currently used by EGD and Union to determine the forecast balance in their PGVA's and the method they use to clear the forecast balance.

56. EGD determines its forecast PGVA balance to be cleared based on a projection of the year end balance in this account. This projected balance is updated each quarter and is designed to be cleared based on the number of months remaining within its test year. The determination of the rider unit rates is therefore a function of the balance in the PGVA as well as the amount of volume the balance will be recovered or refunded from. Designing the rider over the remaining months in the test year has lead to some volatility in the amount of the unit rates and the impact of the unit rates on increasing or decreasing the net effective gas supply charge. This is particularly true for the rider unit rates in the third and fourth quarters when the remaining volume base declines. EGD's current QRAM methodology allows it the discretion to extend its fourth quarter clearing from a three month period to a six month period if the resulting unit rates are viewed as unreasonable given current market prices for natural gas. Although the rider is designed to be recovered over the remaining months in a year, typically the rider unit rate is only in effect for one quarter and is then superseded by the following quarters rider amount. EGD's existing method of determining the unit rates may affect customers differently depending on their seasonal consumption pattern. For example, EGD has customers who consume gas only in the summer months and therefore only receive the impact of the rider on their summer bills.

57. Union determines its forecast PGVA balance to be cleared based on the previous three months actual amount accumulated in its PGVA. Union clears this amount over a twelve month period in each quarter of its QRAM. This has the effect of smoothing the impact of rider unit rates because the volume base is a twelve

month forecast regardless of the amount to be cleared. This adds to the stability in the unit rate determination as the unit rates only fluctuate each quarter as a result of the balance in the PGVA. This serves to reduce the extent to which customers may be affected differently due to their seasonal consumption patterns. As outlined in response to question 4.3, EGD is proposing to adopt the Union methodology for determining the forecast amount of the PGVA balance to be cleared and the application of clearing the forecast amount over a 12 month period.

Issue 5 Effect of Change in Reference Price on Revenue Requirement

58. This evidence responds to the generic question(s) asked within the EB-2008-0106 Issues List, specifically those contained within issue 5, "Effect of a change in the reference price on the revenue requirement".

59. In order to address the specific questions contained within sub-issues 5.1 and 5.2 of issue 5, some general context should be considered along with a review of the existing rates treatment from the financial impacts which natural gas distribution companies incur as a result of changes in gas prices.

60. From a general perspective, in addition to the change in cost of gas, change in gas prices has other related financial impacts on the LDC's. Other rate base related financial impacts which affect natural gas distributors are;

- Gas cost working cash allowance related carrying costs[1]
- Gas in storage value related carrying costs and tax related impacts[2]

These impacts are outlined further in following paragraphs.

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[1] The most recent rate adjustment related calculation for such gas price change related costs as approved by the Board can be found in evidence in EGD's EB-2008-0263 QRAM filing, Exhibits Q4-2, Tab 2, Schedule 1 & Q4-3, Tab 2, Schedules 1-6.

[2] EB-2008-0263, Exhibits Q4-2, Tab 2, Schedule 1 & Q4-3, Tab 2, Schedules 1-6.

61. Within the current models which the LDC's use, the impact of the forecast price of natural gas within these carrying costs, which include interest, tax impacts and return on rate base investment, is included within the revenue requirement determination which the Board ultimately approves as the basis for rate design and recovery. This appropriate treatment should be continued within any future gas commodity pricing and load balancing rate adjustment mechanism.

62. The total carrying costs specifically relating to gas cost working cash requirements are a result of large cash outlays for the purchase of natural gas. In addition to this working cash element, in EGD's and Union's circumstances, further carrying costs are incurred as a result of the volumetric storage balances and associated costs which each company maintains and uses in order to meet the deliverability requirements of all their customers.

63. For the period of time over which the companies are using cash or funds to secure the required sources of natural gas, they are receiving funds from ratepayers through the gas cost component of rates at a different pace, resulting in a timing difference between outgoing and incoming cash. For each of the LDC's, in the past the Board has recognized this timing difference and impacts and allowed an amount of gas cost related working cash within rate base upon which the LDC's should recover their weighted average cost of capital.

64. In addition to the gas cost working cash element of rates, EGD and Union utilize storage facilities. Storage allows EGD to use long haul transport at a 100% load factor and store excess supplies in the summer for withdrawal in the winter thereby reducing the overall costs to the customer. Over a fiscal year, the companies maintain certain gas storage volumes and related values and are required to use a variety of funds in order to have such storage available. For each of the LDC's, in the past the Board has recognized this gas in storage asset

and required funding and deemed it reasonable that the LDC's should recover their weighted average cost of capital to recover the cost of gas in storage .

65. EGD's current Quarterly Rate Adjustment Mechanism approved by the Board, has an element within it which automatically adjusts ongoing rates to reflect the required change in carrying costs for each of these gas cost working cash and gas in storage elements whenever there is a change in the gas cost reference price. EGD notes that an important part of this element is that it adjusts the forecast carrying costs from a revenue requirement perspective and impact on rates, both upwards and downwards. This treatment ensures that any changes in cost elements which are associated with changing natural gas prices are recovered by the LDC's in step with those changing prices.

Issue 5.1 What methodology or methodologies should be used by natural gas distributors for recovering the carrying costs of gas in inventory and related costs?

66. EGD submits that any standardized methodology which is to be employed within any future gas price adjustment mechanism should be as transparent and as easily employed as possible, by each of the LDC's. This would aid in an overall understanding of all parties involved in the review of such pricing mechanisms and would ensure that the LDC's appropriately recover the cost impacts of gas pricing related elements which are largely outside of their control.

67. As previously outlined in this evidence, the current methodology and presentation of cost related impacts relating to changing gas prices which EGD uses within its current QRAM filings, appropriately meets such transparency and level of understanding goals.

68. In the case of Union Gas, the elements of carrying cost recoveries of gas cost working cash and gas in storage inventory values have previously been included

or treated for recovery within a variance account by Union. Such treatment should have achieved the same desired result of having the LDC's appropriately reflect within rates, all of their gas price related financial impacts or costs. Union has indicated that it would agree to employ the same mechanism as EGD currently uses which would end up in the same types of adjustments in rates.

Issue 5.2 Should the revenue requirement (other than gas costs) change as a result of a change in the reference price?

69. EGD submits the answer to this question is yes. As outlined and identified in previous paragraphs, there is evidence which the Board Approved in past proceedings confirming there are other changes in revenue requirement which distributors incur as a result of changes in the reference price. As indicated above, Union Gas proposes to adopt Enbridge's approach / methodology with respect to this issue.

Issue 5.2 i) If so: what component(s) of the revenue requirement should be adjusted?

70. EGD submits that the question of "if so" has been resolved within the response to issue 5.2 in that it shows that other elements of the LDC's revenue requirement do change as a result of changes in gas prices. In addition to the direct elements of gas costs, gas cost working cash and gas in storage revenue requirement changes which occur there are related financial impacts which occur such as capital taxes and GST. As the value of gas cost, gas cost working cash allowance and gas in storage change with changing gas prices, the levels of related capital taxes and GST amounts which the company incurs change as well. The Company incurs increases and decreases in these tax elements dependent on the value of these direct revenue requirement elements upon which rates are set. For issue 5.2 i), EGD submits that it is only reasonable, that just as the Board has recognized and approved the impacts of all of the above mentioned costs or elements in past rate setting and gas price change related rate setting

mechanisms, that any future gas price change related rate adjustment mechanisms need to allow for the same impacts.

Issue 5.2 ii) If so: what methodology or methodologies should be used by natural gas distributors for the purpose of allocating the change in the revenue requirement to the various customer rate classes?

71. As discussed in 5.1 and 5.2 i) above, EGD currently includes in its determination of the revenue requirement the return on rate base impacts for gas in inventory and gas cost related working cash requirements (including GST) resulting from a gas costs change. It also includes the impact of changes in capital taxes. EGD allocates these costs to its customer rate classes and functionalizes them as gas supply and load balancing related based on the principles set forth in its Fully Allocated Cost Study ("FACS"). The FACS is underpinned by the principles of cost causality which are approved by the Ontario Energy Board. The cost drivers or allocator's employed to allocate the costs to each customer rate class reflect the Board approved test year forecasts and are maintained for each of the four QRAM's within a test year.

72. EGD currently recovers the cost from return of gas in inventory and capital tax changes in the load balancing component of its rates applicable to all bundled customers on system and direct purchase. This reflects the fact that stored gas is used to balance total system requirements for winter demand in excess of the average annual demand for both sales service and direct purchase customers. The costs are allocated to the rate classes based on a seasonal space allocator which reflects average winter demand in excess of average annual demand.

73. Gas costs working cash including GST requirements are recovered in the gas supply charge which is only applicable to system gas customers. This reflects the working cash requirement to fund the timing difference between gas cost purchases and gas cost receipts or revenue received from customers. The costs

are allocated to the rate classes based on annual sales volumes, which in turn is recovered on a volumetric basis in the gas supply charges.

74. The principles of cost causality and type of service should be maintained as the standard methodology in the allocation of revenue requirement changes to the various rate classes.

Issue 6 Implications / costs of standardizing pricing mechanism across all natural gas distributors

Issue 6.1 Should there be standardized pricing mechanisms across all natural gas distributors? What are the costs, benefits and implications for ratepayers, gas marketers and natural gas distributors of standardizing the pricing mechanisms across all natural gas distributors?

75. As discussed in responses to Issues 1 through 5, the determination of the QRAM reference price, changes to annualized revenue requirement and derivation of resultant QRAM rates and rider should reflect each utility's individual gas supply portfolio, service types and rate design methodology.

Issue 7 Filing Requirements

76. The response to this issue addresses filing and timeline requirements for QRAM applications.

77. Enbridge's QRAM applications include written direct evidence and supporting schedules for:

- the determination of the forecast reference price (based on a 21-day strip which represents the simple average of future market prices as reported by various indices) and projected year-end PGVA balance;
- the calculation of the change in annualized revenue requirement;

- an allocation of the change in forecast costs to the customer rate classes; and
- the derivation of resultant gas supply and delivery charges.

78. As noted previously, the QRAM process for Enbridge was originally approved on May 30, 2001 as part of RP-2000-0040 and subsequently modified in RP-2002-0133 and RP-2003-0203. Enbridge's QRAM process and associated QRAM rate change applications reflect the Board's Decisions in those proceedings.

79. In QRAM applications Enbridge completes a seven step process as follows:
   1. Determination of QRAM reference price;
   2. Derivation of rate changes and projected year-end PGVA balance;
   3. Submission of QRAM application;
   4. Stakeholder review of the application;
   5. Reply comments from Enbridge;
   6. The Board approval of the forecast reference price, rate changes and PGVA clearances / adjustments and customer rate change notices; and
   7. Implementation of resultant QRAM rates.

80. The associated timeline requirement of the QRAM process is as follows:

Table X: QRAM Process Timeline

Step	Step Duration in Days	Example Due Dates (Oct. 1, 2008 QRAM Application)	Number of Days Prior to QRAM Effective Date
1	21-day strip	15-Aug-08	45
2	14	29-Aug-08	32
3		29-Aug-08	32
4	7	5-Sep-08	25
5	7	12-Sep-08	18
6	13	25-Sep-08	5
7	5	1-Oct-08	0

81. Once the application has been filed with the Board, copies are circulated to stakeholders for review and comment. One week is allotted for this step. If stakeholders submit comments on the application, Enbridge files reply comments with the Board within a week. Thereafter, the Board issues an order disposing of the application in time for the Company to implement the resultant rates during the first billing cycle of the next quarter. Twelve to fourteen days are typically set aside for this step.

82. Enbridge informs all customers of QRAM rate changes and/or PGVA adjustments by means of a bill insert (i.e., customer rate notices) as well as by posting the same information on its website. As part of the QRAM process, Enbridge's rate notices are reviewed and approved by the Board.

83. As discussed above, Enbridge's QRAM process has evolved over time and has achieved a great deal of familiarity with stakeholders. Accordingly, Enbridge seldom receives formal questions or comments on its QRAM applications from stakeholders. As well, the content of QRAM applications, established through the proceedings outlined above, lays out key pieces of information pertinent to a QRAM rate change.

84. In a recent QRAM application Enbridge needed to respond to stakeholder comments related to the Company proposals to extend the clearing of the fourth quarter Rider C over a six month period instead of the standard three month period.

85. In its response to Issue 4, the Company is proposing to clear PGVA balances through a 12 month rolling rider. This addresses concerns with respect to Rider C clearing in the last quarter of the year. This proposal removes Enbridge's discretion with respect to the last quarter rider clearing period and serves to make the Company's QRAM process more streamlined.

Issue 7.1 Should there be standard filing requirements for QRAM applications? If so, what should the filing requirements be?

86. As discussed in responses to Issues 1 through 5, the determination of the QRAM reference price, changes to annualized revenue requirement and derivation of resultant QRAM rates should reflect each utility's gas supply portfolio, service types and customer mix, as well as, cost allocation and rate design methodology.

87. This requirement does not lend itself well to an identical filing requirement. In the Company's view an identical filing requirement (i.e., with identical inputs, format, number of lines or pages, etc.) for QRAM applications for all utilities would not be appropriate or provide any incremental benefit to ratepayers.

88. Having said that, the Company would support an approach where the Board and stakeholders determine which information, and in what order, should be presented by utilities in their QRAM applications. For example, the determination of the QRAM reference price, derivation of the rider, change in annualized revenue requirement, derivation of rates, and rate handbook could form part of a standard QRAM application filing. In Enbridge's view, this would be an appropriate approach as it would continue to reflect the unique elements of each utility's gas supply portfolio, customer mix, service types, etc. rather than trying to impose an identical format to QRAM applications. Enbridge submits, however, that any changes to the existing QRAM application packages should stride to maintain clarity and also steamline and simplify filing requirements.

89. In the response to Issue 2, with respect to QRAM frequency, the Company submitted that a quarterly price adjustment based upon a 12 month forecast period is appropriate for the regulated gas supply option. The Company notes that if the Board finds that a higher than quarterly QRAM frequency is appropriate, then the (current) QRAM application requirements, associated timeline, as well as

customer communication processes, would need to be greatly simplified to accommodate the higher frequency (e.g., monthly), of QRAM rate changes.

<u>QRAM Application Timeline</u>

90. As shown in Table X, in the current QRAM process the determination of QRAM reference price based on a 21-day strip is completed 45 days in advance of the QRAM effective date. The subsequent 45 day period is used to prepare the application, provide for stakeholder review and Company's reply comments, and the Board approval of the forecast reference price, rate changes and PGVA clearances / adjustments and customer rate change notices.

91. In Enbridge's view, shortening of the time gap from 45 days to 30 days between the time QRAM reference price is determined and the QRAM effective date would lead to an improved price signal and would also serve to reduce PGVA balances. Notionally, the closer the forecast end date is to the QRAM effective date, the better the price signal will be with less discrepancy between forecast and actual prices.

92. Additionally, shortening of the time gap would eliminate the month preceding the QRAM effective date as the near month in the collection of gas price data. If October 1st QRAM is used as an example, then the reference price, based on the 21-day strip, would be established in mid-August when September gas contracts are still trading in the market as the near month. Should the QRAM reference price be determined on, for example, September 1st, then September gas contracts would expire and October contracts will be trading as the near month. Typically, during the last two weeks of contract trading as the near month, contracts are subject to a greater price volatility which translates into the future months as well. Therefore, moving the QRAM reference price calculation from mid-month to the first day of the following month would lead to less volatility and contribute to a lesser discrepancy between forecast and actual prices.

93. As discussed above, the Company rarely receives questions or comments from stakeholders on its QRAM applications. Accordingly, the Company notes that the review and approval process could be compressed from the current 25 to 27 day period to (about) a 13 day period while still accommodating all current process components.

94. Hence, the Company is proposing that the 21-day strip period ends 30 days prior to the QRAM effective date and that QRAM application be filed no fewer than approximately 12 business days (i.e., on about 12th or 13th day of the month) prior to the QRAM effective date. The Board approval of the QRAM application would continue to occur on or around the 25th day of the month to allow for timely implementation of the new rates.

95. An example of the proposed QRAM process timeline is presented in the table below.

Table Y: Example of Proposed QRAM Process Timeline

Step	Step Duration in Days	Example Due Dates (Oct. 1, 2008 QRAM Application)	Number of Days Prior to QRAM Effective Date
1	21-day strip	1-Sep-08	30
2	12	12-Sep-08	18
3		12-Sep-08	18
4	5	17-Sep-08	13
5	2	19-Sep-08	11
6	6	25-Sep-08	5
7	5	1-Oct-08	0

96. Enbridge notes that Union Gas supports shortening of the time gap from 45 days to 30 days between the time QRAM reference price is determined and the QRAM effective date.

Issue B REVIEW OF LOAD BALANCING OBLIGATIONS FOR NATURAL GAS DISTRIBUTORS

97. The purpose of this evidence is to provide context regarding the manner in which the Company manages its gas supply portfolio and the associated responsibilities for both system and Direct Purchase (DP) customers.

98. Comments are presented in the following order:
    a) Detailed description of Enbridge's Load Balancing function and Banked Gas Account ("BGA") management mechanisms.
    b) Addressing the specific questions directed by the EB-2008-0106, 8.1, 8.2, 8.3, & 8.4.

Current Process for Direct Purchase (DP) Establishment of Mean Daily Volume ("MDV")

99. In calculating the delivery requirement for General Service customers (Rates 1 and 6), Enbridge uses the most recent 12 months of actual consumption, unadjusted. Contract customers (i.e., Rate 100, 110, etc.) provide their own forecast. EnTRAC divides the total volume by the number of days in the pool term to determine the MDV. The Union Gas model uses an adjustment to account for weather normalization.

100. Once the pool MDV has been determined ("locked"), it does not change for the duration of the pool term. A Union Gas pool MDV can be amended during the term of the contract.

Current Process of BGA Disposition

101. Upon the expiry of the contract, any volume of gas remaining in the BGA that exceeds the contractually stated tolerance of +/- 20 times the MDV (approx. 5% of contracted annual volume), is automatically purchased or sold at a price that compensates Enbridge for sourcing or disposing of that volume of gas. Prices are

calculated automatically by EnTRAC according to an approved method as stated in the Rate Handbook.

102. In the Union Southern Zone, a similar methodology uses a tolerance of +/-4%.

103. Any gas volumes remaining within the contracted tolerance pass over into a Finalized BGA which must be cleared to zero during a disposition period of 180 days. Union Gas does not utilize a similar disposition period.

104. Any gas remaining in the BGA at the end of the Disposition Period is purchased or sold at a price that compensates Enbridge for sourcing or disposing of that volume of gas. Prices are calculated automatically by EnTRAC according to an approved method as stated in the Rate Handbook.

105. While Enbridge encourages active BGA management during the pool term, the only time that a customer is obligated to have their BGA within a given tolerance to stay away from an automatic disposition is at the pool expiry date.

106. Union Gas' methodology differs in that in addition to the previously described conditions at expiry, DP customers are required to have their BGA in tolerance at two predetermined "check points" during the year, on the last day of February and last day of September.

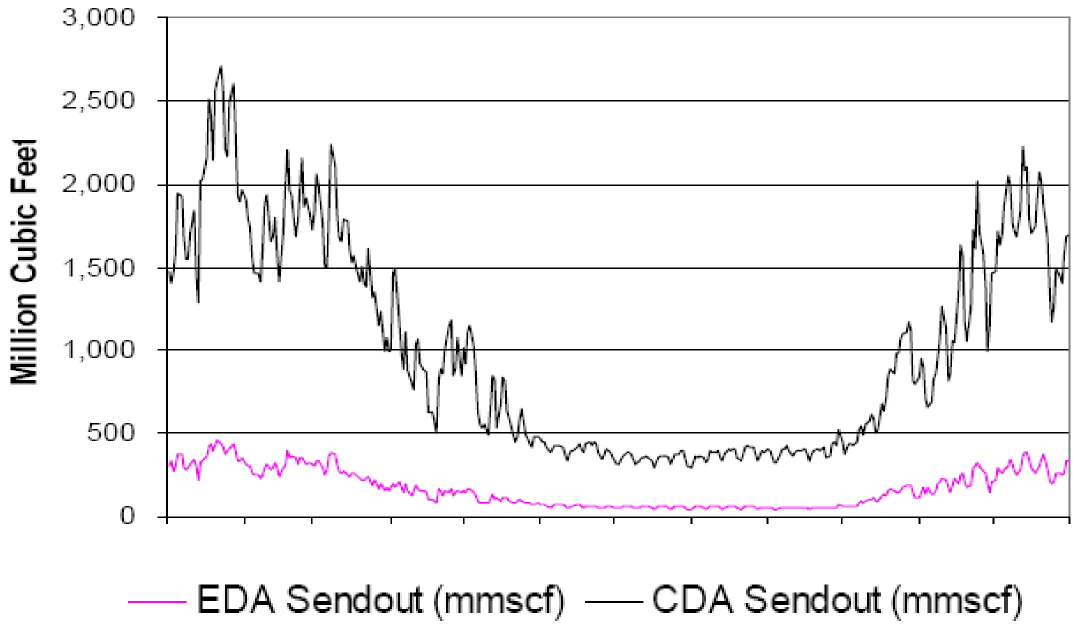
Load Balancing

107. In 2007, Enbridge distributed approximately 12,275.9 10^6m^3 (433.3 Bcf) of natural gas to more than 1.8 million customers.

System Gas	5,226.1 10^6m^3 (184.5 Bcf)
Direct Purchase	7,049.8 10^6m^3 (248.8 Bcf)

108. Enbridge balances the demands of both its system and direct purchase customers on a daily basis. As Enbridge has a high proportion of heat sensitive customers, the daily demands vary significantly throughout the year. See Figure 1.

Figure 1.



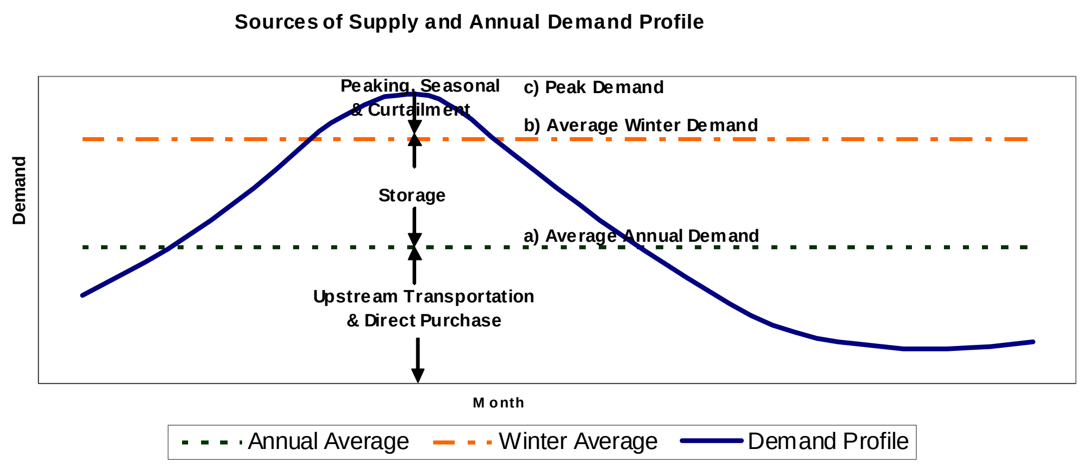
109. Enbridge uses a variety of tools to meet seasonal and peak winter demands:

- company and DP daily pipeline deliveries;
- gas in storage space and associated deliverability;
- peaking and seasonal supplies; and
- gas supplies from curtailed (interruptible) large volume customers.

110. Enbridge uses the SENDOUT planning tool to ensure that the forecasted firm demand of all customers is met in a cost effective manner. On design peak day (the highest point on the demand profile in Figure 2), the supply portfolio consists of approximately 30% daily pipeline deliveries, approximately 57% of storage supply and approximately 13% of peaking, seasonal and curtailment supplies. Daily pipeline deliveries (Average Annual Demand line in Figure 2) are delivered and paid for by both Enbridge and direct purchase customers according to the

volume delivered. Enbridge's cost to provide all load balancing is recovered from both system gas and direct purchase customers according to the Board approved Cost Allocation and Rate Design principles.

Figure 2



111. The forecast cost of the load balancing for System and DP customers is calculated on a forecasted demand and recovered from all bundled customers through the distribution and load balancing components of their rates. To the extent that the actual demand of System <u>and</u> DP customers is different than the forecast (e.g., colder than forecast), seasonal supplies are adjusted (e.g. upward) to ensure that the demand and storage balance targets are met at all critical dates. The cost of the adjusted seasonal/spot purchases are captured in the PGVA. These costs are passed on to both System Gas and DP customers through the clearing of the PGVA which is completed in a manner consistent with the Board approved Cost Allocation and Rate Design process.

112. It is our understanding that Union Gas also provides load balancing to both bundled system and DP customers. It is also our understanding that in Union's Southern Zone, that DP customers must bring gas in or shed gas as the case may

be from their system at specified “check points” during the year as instructed by Union Gas.

113. Enbridge DP customers must take specific actions at the end of their DP contract to bring their BGA into balance although they have an opportunity to do so during the year with some restrictions depending on the time of year.

BGA Management.

114. As previously noted, Enbridge and Union Gas offer similar tools/options for customers to adjust debit or credit positions of their BGA. Once accepted, these transactions are considered as firm by Enbridge, but are offered on a restricted basis depending on system requirements. For example, suspensions are not generally available during all of the peak winter/heating months when Enbridge typically requires all its own and all DP deliveries into the franchise area to meet demand.

115. The equivalent mechanisms on the Union Gas (Southern Zone) are generally offered all year, but are subject to interruption at Union Gas’ discretion. It is Enbridge’s understanding that the gas hub and trading center of Dawn residing within the Union Gas franchise area facilitates an enhanced ability for customers to make short notice arrangements for supply without transportation implications. This flexibility assists customers to meet the required check point and expiry tolerances throughout the year while Union Gas maintains the overriding ability to manage the system.

Issue 8.1.a. Should there be standardized load balancing mechanisms for Union and Enbridge?

116. The load balancing mechanisms used by Enbridge and Union Gas to supply the demand of their systems are appropriate and fundamentally the same as both provide load balancing to system and DP bundled customers. The following

addresses the two related items where Enbridge and Union Gas use different approaches:

- MDV reestablishment for pools including weather normalization used to determine the MDV, and
- mechanisms for “check point” BGA management.

117. Accepting that an MDV should be as reflective of a pools actual requirement as possible, Enbridge agrees with the concept of a standardized approach to establishing the pool MDV using adjusted (weather normalized) consumption history, and allowing for threshold-based changes to the MDV during the pool term. This will be discussed further in point 8.4.

118. While the tools that Enbridge and Union Gas make available to customers and Gas Vendors to manage the BGA are generally similar, they differ in availability. Union Gas offer tools year round subject to interruption, while Enbridge tools are firm but are restricted during peak winter demand months (limited Suspensions) and during late storage injection season (limited Make Ups). The other area of difference is single vs. multiple BGA check points. The geographical location of each utility and an in-franchise trading hub such as Dawn affects both of these differences.

119. Our understanding of an interrupted Suspension would mean that the customer would have to replace deliveries on short notice. A large and fluid trading hub within the franchise generally means available supply with little or no transportation issues. In Enbridge’s case, interrupting the Suspension of a customer in an area hundreds of kilometers from the trading center could create difficult transportation challenges for the customer and therefore, risk to the Gas Distributor from customers failing to comply with an interruption requirement.

120. With a multiple check point approach customers must have the ability to respond to the check point requirements. To accomplish this Enbridge would have to increase the availability of BGA mechanisms throughout the year. However, Enbridge could not continue to guarantee them as firm as it would put the system supply at risk during peak system constraint periods. Enbridge would have to offer them as interruptible (as does Union Gas) which would put customers at risk from the restricted ability to make alternative arrangements.

121. Standardizing the load balancing and BGA management tools/mechanisms to include check point balancing is not appropriate as it presents difficulties due to physical locations of each utility and operating structure of each distribution system.

Issue 8.1.b. What are the costs and benefits to ratepayers, gas marketers and natural gas distributors of the current mechanisms used by each of Union and Enbridge?

122. While Union Gas' two check point model requires direct purchase customers to manage their BGAs and associated costs at specific times of the year, the Enbridge approach is to load balance the system as a whole, and then recover all costs from customers through the PGVA. Therefore, there wouldn't be an appreciable benefit to ratepayers of one approach over the other.

123. As noted above, Union Gas' model requires customers to take action at two additional points during the year that the Enbridge model doesn't, so there could be a perceived advantage in the Enbridge model from less administration on behalf of the Gas Marketers. However, as maintaining BGA balances reasonably close to tolerance is a good business practice nonetheless, there is not an appreciable benefit in one vs. the other approach.

124. Both models have proven track records of performance through their respective Gas Distributors and their operating platforms (Unionline and EnTRAC) and both approaches pass load balancing costs to the customers. Enbridge does not perceive that there is a substantial benefit from one over the other approach.

Issue 8.1.c. What are the costs, benefits and implications to ratepayers, gas markerters and natural gas distributors of standardizing the load balancing mechanisms for Union and Enbridge?

125. For Enbridge to standardize its mechanisms to include weather normalized MDV establishment, MDV reestablishment, and multi point balancing, would require large scale changes to EnTRAC, our contracts, business processes, policies and tariffs.

126. The preliminary cost estimate (in advance of formal investigation) for full standardization which would include a “check point” BGA balancing function would be approximately $8.5 million.

127. The estimate to develop a weather normalized MDV establishment, MDV amendment/reestablishment without the “check point” function would involve most of the same activity noted above but on a more limited scope. The preliminary cost estimate (in advance of formal investigation) is $3.7million.

128. Implications to all parties would be substantial in that changes to EnTRAC and supporting systems and processes would have to be designed, tested and implemented, and training for all internal and external users and support personnel undertaken.

Issue 8.2 What mechanism(s) for load balancing should be used by natural gas distributors?

129. The mechanisms used for load balancing should reflect each distributors' composite customer demand and physical location/constraints of the utility. For these reasons, both Enbridge and Union Gas' approaches to load balancing are appropriate and effectively support the reliable delivery of natural gas in each distribution area.

Issue 8.3 What are the implications of different balancing mechanism(s) in relation to the issue of drafting?

130. In Enbridge's view the implications of different balancing mechanism in relation to drafting are narrow, if any. Enbridge accounts for drafting and packing in its gas supply plan through planned deliveries and consumption. Any unplanned occurrence of packing and/or drafting are generally the result of weather that is colder or warmer than forecasted and not deliberate actions on the part of DP customers. Nevertheless, Enbridge has provisions in place to discourage deliberate drafting. For example, penalty provisions are in place for daily consumption greater than contracted levels and unplanned drafting is managed by limiting additions to customer pools that deliver gas under a fixed MDV.

Issue 8.4 Should the MDV/DCQ reestablishment process be standardized, including in relation to weather normalization of MDV/DCO volumes?

131. Notwithstanding the comments made in 8.1.c. that consider the full breadth of standardization including check point balancing, an MDV that most accurately reflects the actual requirement of a pool reduces the potential for balances greater than the forecast in the BGA. This means less BGA management for pools and greater assurance for Enbridge that the demand is reflective of the arranged supply. Therefore, Enbridge proposes to adopt MDV reestablishment process and harmonize it with Union Gas.

Issue C. COST ALLOCATION

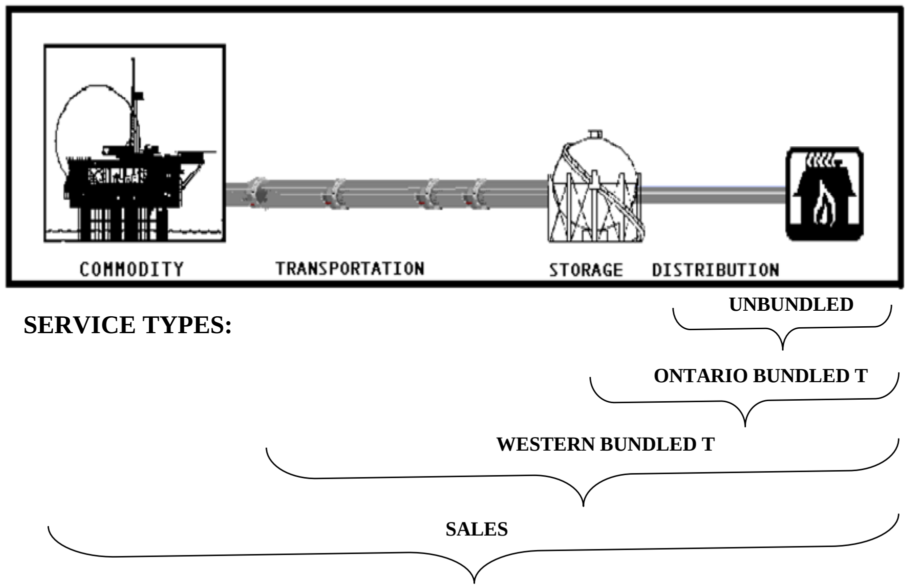
132. This evidence addresses the cost-allocation methodology that is applied to gas costs and the underlying costs that are attributable to the regulated gas supply and the direct purchase options. The evidence begins by providing background information on the types of services provided by Enbridge, the distinction between regulated (or system) gas supply and the direct purchase option, and the method of allocating costs between load balancing and distribution services. Responses to the specific issues pertaining to cost allocation follow, and are addressed in the context of the background information provided.

Types of Service

133. Enbridge currently provides a number of services that enable all customers to have a choice in the way they receive services from the utility. Figure 1 is a pictorial representation of these services.

134. The most comprehensive type of service is that of System Sales where the Company acquires and sells to the customer all of the customer's natural gas requirements -- commodity, transportation, storage, load balancing and distribution services. Western Bundled T (transportation) service is provided to customers who choose to purchase their own commodity or gas supply. Ontario Bundled T (transportation) service is for those customers who opt to purchase their own commodity and arrange for the transport of commodity to Ontario. Unbundled customers receive distribution service from Enbridge, but can choose to contract for unbundled storage in addition to the purchase of their own commodity and the transport thereof. Enbridge provides load balancing and distribution service to all customers.

Figure 1



135. Table 1 further explains the components included in the choice of service provided.

Table 1

Choice of Service	Commodity	Transport	Load Balancing & Storage	Distribution
Sales	☑	☑	☑	☑
Western T		☑	☑	☑
Ontario T			☑	☑
Unbundled				☑*

*Note: Unbundled customers receive limited load balancing service from Enbridge.

System Gas and Direct Purchase Options

136. Since the deregulation of the natural gas industry in 1985, the marketplace for natural gas has evolved enabling customers to make their own arrangements for gas supply and associated transportation to Enbridge's franchise area or to do so through a gas vendor. Such arrangements are accommodated through direct

purchase options. Enbridge continues to supply natural gas (i.e. “system gas” or “system supply” or “sales service”) to customers who have not selected the direct purchase option.

137. Currently, about 40% of Enbridge’s customers are on direct purchase contracts representing approximately 60% of the annual volumes throughput.

138. Enbridge accommodates activities for both supply options through system gas and direct purchase management. Regardless of customers’ supply arrangements, Enbridge provides safe and reliable delivery service to all customers.

System Gas - Regulated Gas Supply Option

139. Enbridge provides system gas to its residential, commercial, and industrial customers who do not procure their own gas supply either on their own, or through gas vendors.

140. The rate Enbridge charges to customers for system gas (i.e. gas supply charge) is subject to regulatory approval and based on a 12-month forecast of commodity prices adjusted each quarter through the Quarterly Rate Adjustment Mechanism (QRAM) process.

141. The reference price is comprised of commodity, transportation, and load balancing costs. For rate design purposes, the Company uses the Empress reference price inclusive of fuel to cost its commodity purchases and receipts. This commodity cost is recovered from system gas customers through the Company’s gas supply charge. Any premium or discount over the deemed commodity cost is classified as transportation and load balancing. Transportation costs are recovered from System gas and Western T customers, and load balancing costs are recovered from all customers.

142. In addition to the commodity costs, Enbridge's gas supply charges also recover: commodity-related bad debt expense and commodity-related working cash requirement (i.e. return on rate base), as well as the system gas fee. The derivation of the gas supply charge can been seen in the QRAM filing under Exhibit 3, Tab 4, Schedule 4, page 1.

143. Bad debt costs arise from the non-payment of customers bills. Commodity-related working cash is required to bridge the gap between the time the utility pays for its gas costs and the time revenues are received from customers. The system gas fee is designed to recover the incremental costs of providing system gas management.

144. The Board has approved the incremental costing approach for both system gas and direct purchase management activities in EBRO 497. Enbridge and Union Gas both determine the level of system gas and direct purchase management fees based on the incremental costing approach.

145. Enbridge has maintained the incremental costs and resulting fees for both System Gas and Direct Purchase for a number of years, most recently as based on the Settlement Agreement from EB-2005-0001 dated August 10, 2005[3]. The settlement language is as follows:

> The Company agrees to maintain for 2006 both: (i) the current structure, level and administration of the system gas fee and direct purchase administration charge; and (ii) the Board approved costs allocated to such fees in 2005 (i.e. $0.88 million to system gas and $1.56 million to DPAC) on the understanding that the Board will be examining the costing of such fees on a fully allocated or incremental basis in the context of its pending NGF generic proceeding on Cost Allocation of Regulated Gas Supply expected to be held in 2006.

[3] Settlement Agreement, EB-2005-0001, August 10, 2005, Exhibit N1, Tab 1, Schedule 1, pp. 35-36.

<u>Direct Purchase Supply Option</u>

146. Customers have the option to purchase gas supply in the marketplace or from gas vendors under a contractual commitment for a fixed or variable price over a fixed term. Unlike the utility price which is cost-based and subject to regulatory approval, prices charged by gas vendors are market-based subject to competitive forces.

147. It is important to highlight that direct purchase customers who procure their supply from gas vendors remain distribution customers of the utility. The utility continues to provide load balancing and distribution services to direct purchase customers based on Board-approved rates.

148. Enbridge charges a monthly Direct Purchase Administration Charge (DPAC) to direct purchase customers or vendors for each direct purchase pool plus a per account fee. Each contract or pool can contain a varying number of accounts, grouped by the terms and conditions of the contract. The DPAC is designed to recover the incremental cost of managing / facilitating direct purchase gas supply.

149. As noted in the previous section, Enbridge has maintained the incremental costs and resulting fees for both System Gas and Direct Purchase for a number of years, most recently as based on the Settlement Agreement from EB-2005-0001 dated August 10, 2005[4].

Allocation of Load Balancing and Delivery Costs

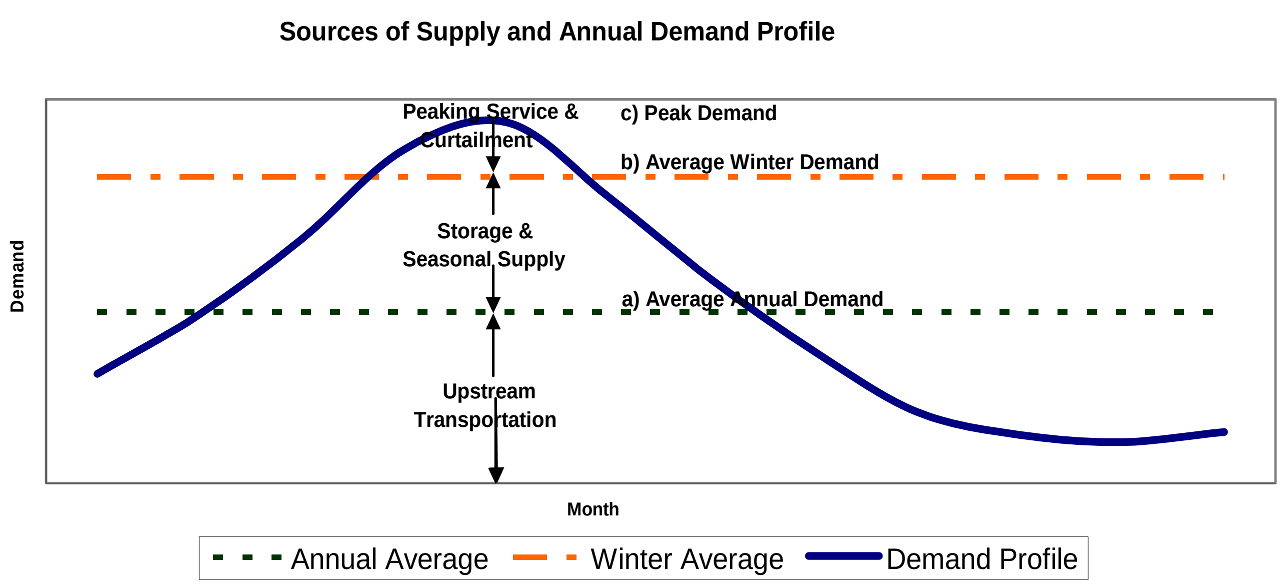
150. Enbridge Gas Distribution uses a variety of tools / services to meet the annual, seasonal, and peak winter demands of all its customers on system gas and direct purchase. As discussed in previous sections, the direct purchase option enables customers to make their own arrangements for gas supply and associated transportation to the Enbridge's franchise area or to do so through a gas vendor.

[4] Settlement Agreement, EB-2005-0001, August 10, 2005, Exhibit N1, Tab 1, Schedule 1, pp. 35-36.

151. Figure 2 illustrates the typical annual demand profile for a gas distribution utility including sources of supply and assets used to meet average annual, average winter, and peak demands, and the drivers / factors used for allocating these costs.

152. This representation reflects the current operating practice of the Company. The details and the rationale for each element of the current methodology were discussed and subsequently approved by the Board in RP-2003-0203.

Figure 2:



153. The Company has not experienced material changes in its operating practice since the Board Decision in RP-2003-0203. The highlights of the existing approach are presented below.

154. It is important to emphasize that, other than for gas supply / commodity and upstream transportation costs that are a function of system gas or direct purchase arrangements, load balancing and delivery costs are recovered from all customers. Allocation of load balancing costs is based on each customer class' seasonal and daily load balancing requirements. With respect to the distribution network costs (i.e., delivery costs), the allocation of costs is based on drivers such as each customer class' contribution to peak day demand (such as mains costs) or on the number of customers in each rate class (such as billing costs).

Upstream Transportation

155. Enbridge contracts for upstream capacity on pipelines such as TCPL, Vector and Alliance. Upstream capacity is contracted at 100% load factor to meet annual average demand for system gas and Western T-Service customers. Ontario T-Service customers arrange for their own transportation. To reflect this operating practice, upstream transportation costs are classified as 100% annual demand and are allocated volumetrically based on annual deliveries net of Ontario T-Service volumes by rate class.

156. It should be noted that upstream transportation costs are currently rolled in as part of the load balancing charges in customers' bills.

Storage

157. Storage assets and associated transportation (i.e. storage costs) are used as a load balancing tool for both system gas and direct purchase customers to manage supply and demand on a daily basis. Storage costs are classified between space and deliverability, depending on the type of demand that is needed to fulfill.

158. Storage space is used to satisfy average winter demand in excess of the average annual demand. These costs are allocated on the storage space allocation factor. Storage deliverability is incurred to meet the excess demand over the average

winter day. These costs are allocated on the rate class contribution to the excess demand over the average winter day consumption.

159. These costs are recovered from system gas and direct purchase customers in the delivery charge. Delivery charges are the same within a rate class for both system gas and direct purchase customers.

Peaking Service, Seasonal Supply Costs, and Curtailed Volumes

160. Peaking service and curtailed volumes are used to supplement storage deliverability for meeting peak demand. Seasonal supplies are used to supplement storage space for meeting seasonal or winter demand. In that regard, peaking service costs are allocated on the same basis as storage deliverability, and seasonal supply costs are allocated as storage space costs are.

161. These costs are recovered from system gas and direct purchase customers in the load balancing charge. Load balancing charges are the same within a rate class for both system gas and direct purchase customers.

162. Load balancing and delivery costs are recovered from all customers based on their respective seasonal and daily load balancing requirements. Distribution costs are allocated on drivers based on each customer class's contribution to peak day demand (e.g. mains costs) or on the number of customers in each rate class (e.g. billing costs).

Issue 9.1 What activities and underlying costs should be incorporated into the regulated gas supply and direct purchase options?

163. As discussed above, in addition to commodity costs, Enbridge's gas supply charges also recover: commodity-related bad debt expense and commodity-related working cash requirement (i.e. return on rate base), as well as the system gas fee.

164. Bad debt costs arise from the non-payment of customers bills. Commodity-related working cash is required to bridge the gap between the time utility pays for its costs and the time revenues are received from customers.

165. The system gas fee is designed to recover the incremental costs of providing system gas supply. It is charged to system gas customers on a volumetric basis. These incremental costs represent costs incurred by Enbridge for the following functions:

- Gas Acquisition
- Contract Management
- Nominations
- Invoicing and Payment Processing
- Reporting
- Demand Forecasting and Supply Planning

166. Direct Purchase incremental costs represent costs incurred by Enbridge for the following functions:

- Administration & Contract Management
- Nominations
- Invoicing and Payment Processing
- Reporting
- Direct Purchase Billing Adjustments

167. Enbridge is proposing that the system supply fee and the DPAC continue to be based on incremental costs as approved by the Board in previous proceedings. This approach identifies costs that are incremental to support system supply and the direct purchase option from other distribution services. In other words, only the associated incremental costs would be eliminated should those services no longer be provided or supported by the utility. Doing so allows both services to be treated as separate and incremental to the core distribution function of the utility.

168. Similarly, as the system gas fee and the DPAC are based on incremental costing, the utility retains its ability to recover or shed the costs incurred for either service without the risk of unrecoverable costs should customers choose one option over the other. The utility maintains a neutral stance as to the customer election of either service, and simply functions to fulfill the service requirement without the need for exit fees or other constraints to customer mobility.

169. This position is consistent with the Board's view, as expressed in Natural Gas Forum report[5]:

> The Board concludes that the utilities should continue to provide a regulated gas supply option. However, the regulated gas supply option should be seen as a default supply option and structured accordingly. … Also, the Board does not believe it is appropriate for the utilities to promote and/or to market the regulated gas supply option to their customers. The Board does believe, however, that it is appropriate to inform customers of the terms and conditions related to the regulated gas supply option and, in particular, of their unilateral right to switch to a competitive supplier.

170. In contrast, a fully-allocated approach to costing would necessitate the recovery of other costs through system gas and DPAC fees which are not directly related to the service. Should a fully-allocated approach be pursued in the costing of system supply and direct purchase management, if customers opted to select one option versus the other, fully allocated costs would not be recovered because the elimination of the service would not eliminate the cost.

171. The incremental costing approach would ensure that customers retain full mobility between system gas and direct purchase options.

172. As stated above, Enbridge has maintained the incremental costs and resulting fees for both System Gas and Direct Purchase for a number of years.

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[5] Natural Gas Regulation in Ontario: A Renewed Policy Framework, Natural Gas Forum, March 30, 2005, page 62-63.

173. Should the incremental approach continue to be applied, Enbridge is proposing to update its incremental costs for the 2010 rate adjustment application. As an illustration, the estimated system gas fee for 2009 is approximately $1.14 million. Currently, the incremental cost of system gas is held constant at $0.88 million, following the Settlement Agreement for the 2006 test year. Again, as an illustration, the 2009 estimated incremental direct purchase management costs are approximately $3.18 million, similarly held at $1.56 million under the same agreement.

174. This update of incremental costs is revenue neutral for Enbridge. In other words, it does not affect the revenues derived through the Company's Incentive Regulation (IR) formula. The proposed update would ensure that appropriate incremental costs are recovered via fees from system gas and direct purchase customers rather than through the Company's delivery rates (which would be reduced accordingly). Doing so would align cost recovery with the service provided.

<u>Direct Purchase Administration Charge (DPAC) Fee Structure</u>

175. Further, in Enbridge's view, the current DPAC fee structure no longer reflects the structure of the direct purchase market. The Company proposes a new fee structure that will improve the alignment associated with direct purchase management and developments in the market.

176. The current fee structure sets a fixed base charge at $50 per month for each direct purchase contract and account charges of $0.50 per month for new accounts and $0.15 per month for renewal accounts. Monthly charges for the combined fixed and variable components cannot exceed $815 per contract pool.

177. The current structure poses fee recovery risk for the following reasons. With the implementation of Enbridge's Energy Transaction, Reporting, Accounting and Contracting System (EnTRAC), customers and gas vendors are able to

amalgamate multiple direct purchase pools into a single pool. This is enabled by an EnTRAC feature that accommodates multiple price-points within a single pool contract. Also, due to changes in the Consumer Protection Act which has changed affirmative renewal requirements, gas vendor renewal rates have declined. Similarly, gas vendors have seen a decline in new customer enrollments in recent years. And finally, the $815 maximum charge per pool prohibits full cost recovery for contracts that may contain a larger pool of new and renewing accounts. For pools with a very large number of accounts, the transaction support costs are substantially higher than for a pool consisting of only a few accounts. The maximum charge per pool suggests that issues affecting both are the same. Although variable charges apply only on new and renewing accounts, administrative costs are still incurred by the majority of accounts which are active yet unchanged.

178. Enbridge proposes to eliminate the distinction between new and renewal accounts and to remove the maximum charge per pool. In its place, the proposed fee will consist of a base charge of $75 per month, and an account fee of $0.26 per month. The structure is similar to Union's current DPAC structure.

179. The proposed base charge considers full recovery of the estimated incremental costs of supporting direct purchase from direct purchase customers alone. Enbridge proposes to increase the monthly DPAC base charge from $50 to $75 per pool per month to enable recovery of the full incremental costs on a consolidated pool base.

180. It also proposes to charge a single variable fee for all accounts of $0.26 per account per month. This reflects a shift away from manual contracting and enrollment processes once managed by Enbridge, to the self-service EnTRAC system accessed by vendors and customers. The automation has streamlined the process so that costs are no longer driven by the nature of the account.

181. The proposed fee will not hinder gas vendors from seeking cost efficiencies through amalgamation; it will simply allow for improved cost recovery on the general maintenance of all customer-based direct purchase pools and the appropriate recovery from larger pools which create higher administration and support costs.

Issue 9.2 What asset-related costs should be allocated to load balancing and delivery and how should the costs of these services be allocated between system/regulated supply and direct purchase customers?

182. While gas supply and upstream transportation costs are recovered from system gas and direct purchase customers according to the supply arrangements made on their behalf or directly obtained through gas vendors, load balancing and delivery are provided by the utility to all customers. In that respect, while cost recovery of commodity and transportation vary between system gas and direct purchase customers based on the type of service elected, load balancing and delivery charges apply to both types of customers equally within the rate class.

183. Load balancing and delivery costs are incurred in response to the combined annual, winter, and peak demands of all customers on Enbridge's system. As detailed in the background section, upstream transportation costs are incurred to meet annual demand and are recovered as part of the transportation charge. Costs associated with storage space are incurred to satisfy the excess of average winter demand over annual demand. Consequently, these costs are recovered from all customers in their delivery charge based on the allocation of storage space by rate class. Similarly, storage deliverability costs are incurred to satisfy the excess demand over the average winter demand. Costs are recovered in the delivery charge on the basis of each rate class's contribution to excess demand over average winter demand. All these costs are recovered equally within the rate class from both system gas and direct purchase customers in their load balancing and delivery charges.

184. Load balancing and delivery costs are recovered from all customers based on their respective seasonal and daily load balancing requirements. Distribution costs are allocated on drivers such as each customer class's contribution to peak day demand (e.g., mains costs) or on the number of customers in each rate class (e.g., billing costs).

185. Enbridge is not proposing any changes to the methodology currently in place. The requirements for different services ultimately determine the nature of the services arranged on behalf of customers. The Company submits that the current Board-approved cost allocation methodology reflects operating practices, thereby upholding the principle of cost-causality as it aligns costs with the services for which the costs are incurred.

Issue 9.3 Under what circumstances should natural gas distributors be permitted to change cost allocation principles, percentages, or amounts as between distribution, load balancing, and commodity?

186. Enbridge believes that cost allocation principles are set based on shared values that all stakeholders strive to uphold. From that standpoint, cost-causality is the guiding principle of cost allocation, and when applied consistently, results in just and reasonable rates. It is Enbridge's position that the principles for cost allocation should not change.

187. However, to the extent that there are changes in operating conditions, the Company would apply to make adjustments to its cost allocation methodology during the annual rate adjustment process.

188. The cost allocation methodology is approved by the Board through the Company's annual rate adjustment process. Enbridge cannot change its methodology without the Board's approval.

189. Allocation percentages change annually to reflect new volumes, peak demand, customer numbers, etc. and are approved by the Board in the Company's annual rate adjustment process. Allocation percentages do not change with QRAMs.

Issue D: Billing Terminology

Background

190. Enbridge Gas Distribution bills its customers on a monthly basis in three different formats: mass market residential and small commercial accounts, monthly statements (a consolidated bill of individual mass market accounts) and large volume accounts. In January 2008, Enbridge Gas Distribution launched a redesigned bill for mass market customers. The mass market bill was redesigned to provide for improved presentation of billing information, making the bill easier for customers to read and understand. This redesign was undertaken, in particular, to more clearly differentiate Enbridge Gas Distribution charges from charges of other Energy companies arising from our Open Bill program. As part of the bill redesign initiative, the Company conducted several focus groups through which, options on bill format and terminology were tested. The results of these focus groups have been incorporated into the bill presentment that the Company uses today.

191. Enbridge is also currently undertaking a replacement of its legacy Customer Information system with a new Customer Information System based on SAP software. The planned implementation date for this system is April 2009. At that time, Enbridge will also be updating the layout and format of both the Monthly Statement and Large Volume bills, consistent with the changes made to the Mass Market bills in 2008. Also, at that time, Enbridge will unbundle the transportation charge component on the bill, consistent with Union Gas.

192. With the latest mass market bill redesign launched in January 2008, bill presentment (layout and format) is consistent with that of Union Gas and includes a summary page, detailed commodity page and in the case of EGD, a third page which contains services from other energy companies. Both Enbridge and Union Gas also include a graph of consumption usage, definitions, pertinent phone numbers and various bill messages. Terminology is very consistent and also in keeping with the language style of each organizations bill.

193. As mentioned above, terminology is very consistent in that both companies use similar language to refer to the same type of customer charge. For example, Enbridge refers to the monthly customer charge it charges its customers as “Customer Charge”, while Union refers to this charge as “Monthly Charge”. With respect to the terminology used to refer to the monthly cost to deliver gas, Enbridge refers to this charge as “Delivery Charge” while Union Gas refers to this charge as “Delivery”. Another example, among many, would be the language used to refer to the cost of the commodity used by a customer. Enbridge uses the term “Gas Supply Charge” to represent the cost of the commodity, while Union Gas uses the term “Gas Used”. In this particular case, Enbridge tested both terms during focus groups conducted during the bill redesign that was launched in January 2008. Customers in those focus groups preferred the term “Gas Supply Charge”, which is why this term is used on Enbridge’s bill today.

194. There are other important factors that also need to be considered in this analysis, such as the demographics of Enbridge’s customer base. Currently, 40% of Enbridge’s residential customers are on a commodity broker contract. Also, Enbridge and Union Gas operate in exclusive franchise territories, and as such, there are very limited circumstances in which a customer would receive a bill from both Union Gas and Enbridge. To some extent, there will always be justifiable differences given the different rate structures across the utilities.

Issue 10.1 Should natural gas distributors be required to use standard billing terminology? If so, what should the standard billing terminology be?

195. If there is to be standardization in billing terminology, first, it would be necessary to jointly reconcile terminology included in the Enbridge Rate Handbook with that of Union Gas and other Natural Gas Distributors. There would also need to be an ongoing mechanism to coordinate bill messaging between Enbridge and Union Gas. This mechanism would involve such things as coordinated message development, agreement on what is appropriate terminology, coordinated focus group testing of terminology, agreement on what a successful result would be, and coordination of the implementation of the new terminology. This may add unnecessary time and cost to the process of billing our customers. In addition, there are limitations that need to be considered, for example, there is a limitation on the number of characters that can be used in a bill message to ensure legibility.

196. Costs to implement such a change would be at least $0.6 million. This would include system changes to change Enbridge's current terminology to match that of Union Gas, the development, printing and mailing of communication materials in the form of bill inserts to communicate the change to customers, in addition to updates that would be required to all of Enbridge's existing communication materials such as new customer packages, changes to the Company's website and change to the Rate Handbook. The training and education of our Service Provider to understand and be able to explain line items on the bill would also need to be considered.

197. In addition to implementation costs, as noted above, with the increased coordination and perhaps regulatory oversight on terminology to be used, there will be an increase in the ongoing costs for implementing new billing terminology. If the Board determines that billing terminology is to be standardized then associated implementation and ongoing costs should be recovered by the means of a deferral account.

198. In summary, we have consistency, but not standardization in billing terminology between Enbridge Gas Distribution and Union Gas. Customers have already told Enbridge through participation in focus groups which terms they like for billing terminology. Given this, the cost of implementing this change and the ongoing costs of maintaining coordination, in addition to the extremely limited customer overlap between the companies, it is our submission that there is no customer benefit in making this change.

Issue E IMPLEMENTATION ISSUES

Issue 11.1 What are the costs of implementing changes to methodologies currently used by natural gas distributors?

199. The implementation costs stemming from potential changes that could result from this proceeding must be recovered by the means of a deferral account. This approach is compatible with the Board's previous decisions on issues / matters that are Board-initiated or market enabling and ensure the utility and its customers are kept whole with respect to implementation costs.

200. The sections A through D discuss the Company's evidence on the issues in this proceeding. The anticipated impacts for certain issues are discussed below:

Trigger Mechanism:

201. As discussed in the Company's response to Issue A item 1.1, there are no advantages and/or disadvantages to the utility or negative implications on customers from removing the trigger. The elimination of the trigger mechanism would not lead to any additional costs or savings as the Company will continue to follow processes that it normally carries out every quarter.

<u>Deferral and Variance Account and Disposition Methodology:</u>

202. At Issue 4.3 the Company is proposing to dispose of PGVA balances using a 12-month rolling rider methodology. Besides the methodology change, additional customer communication will be required. While the Company would use regular QRAM communication channels to convey the changes to customers, an additional expense of approximately $100,000 is anticipated. Such additional costs should be captured in the proposed deferral account.

<u>Load Balancing Obligations for Natural Gas Distributors:</u>

203. As noted in the evidence at Section B, the Company is not proposing to implement Multipoint Balancing. The cost of this project is estimated at approximately $8.5 million.

204. The adoption of a multipoint balancing mechanism would involve enhancements in EnTRAC to accommodate two more BGA checkpoints such as February and September. Additionally, EnTRAC changes would be required to incorporate automated notices to customers and automated capabilities to the BGA gas disposition process if customers fail to take required action within a stipulated time.

205. EnTRAC would also need further features to enable the Company to generate monthly reports on BGA positions for various customer accounts and pools. The system would also require revisions to accommodate changes to restriction on BGA management activities.

206. Once EnTRAC has been enhanced with these changes, the Company would need to integrate it with other systems such as CIS. The integration is comprehensive in nature and represents a large portion of implementation costs.

207. The Company is proposing to implement MDV reestablishment. This project also involves a number of enhancements to EnTRAC. The project cost for this feature is estimated at approximately $3.7 million.

Price Adjustment Frequency and Forecast Periods:

208. The Company is not proposing a change to price adjustment frequency. In case the Board decides in favour of a higher price adjustment frequency, the Company would require additional staff to accommodate incremental work in areas such as gas supply, rate design, customer communication, etc. Further, the current agreement with customer care provider stipulates up to four rate changes in a year. An increased number of rate adjustments would increase the Company's costs in this area. Higher communication costs would also be incurred with more rate adjustments. Costs to accommodate a higher price adjustment frequency would be at least $1.0 to $1.5 million a year.

Billing Terminology:

209. At stated at Issue D, the Company does not propose to change its billing terminology. While changes to the billing terminology may appear simple on surface, they would impact multiple areas such as customer care / CIS system, customer communications, and contract compliance (for example, customer contracts would need amendments / revisions to incorporate changes in billing terminology). Costs to implement changes to billing terminology would be at least $0.6 million.

Issue 11.2 Who should bear those costs?

210. The implementation costs must be recovered from customers and/or retailers who are impacted and are anticipated to benefit from changes to methodologies currently in place. Such an approach is compatible with the Board's previous decisions on issues that are Board-initiated or market enabling.

Issue 11.3 How and when should any such changes be implemented?

211. As has been the case in previous Board initiated proceedings such as NGEIR, implementation costs should be recovered by the means of a deferral account.

212. The implementation of various changes would require varying amounts of time depending on the complexity of changes and their respective impact on a range of operations and key systems within the Company. The changes that involve enhancements to EnTRAC, CIS, and other systems would require great care in planning and execution to avoid operational disruptions and an error free implementation. Therefore, adequate time would be required for preparation and implementation of such changes.

213. The simpler changes such as removal of the trigger mechanism and shift to clearing of PGVA balances over 12 month rolling period could be implemented faster, perhaps as early as January 2010 depending on when the decision to proceeding with these changes is made.

214. On the other hand, more complex changes such as MDV re-establishment or a change to price adjustment frequency likely would not be implemented earlier than 2011.

		Current Process		Proposal
A	*REVIEW OF QRAM FOR GAS LDCs*	Enbridge	Union	
1	*Trigger Mechanism*	$0.005/m3 trigger for utility price and rider	No trigger	Enbridge to adopt "No Trigger" Mechanism
2	*Price adjustment frequency and forecast period*	Quarterly price and rate adjustments Forecast period = 12 months	12 month Forecast	No Change
3	*Calculation of reference price*	Common methodology to determine reference price. Reference price calculated by utility reflects utility specific gas supply mix.	Common methodology to determine reference price. Reference price calculated by utility reflects utility specific gas supply mix.	No Change
4	*Deferral and variance A/C disposition*	Rider C cleared to achieve zero balance in PGVA at end of year. True up for all PGVA components at year end.	Recovery of balances using 12 month rolling rate rider	Enbridge to adopt 12 month rolling rider methodology
5	*Impact on Revenue Requirement (re. reference price)*	Quarterly changes to gas costs and carrying cost of gas in storage and working cash requirement	Carrying costs recovered through annual deferral disposition	Union to eliminate Intra-Period WACOG deferral account and adjust delivery rates with QRAMs
6	*Implications/costs of standardizing pricing mechanisms*			No Change
7	*Filing requirements*			Utilities propose streamlined QRAM information filings and timeline efficiency
B	*LOAD BALANCING (LB)*	a) Single BGA management checkpoint (at account anniversary) b) MDV re-established at contract anniversary	a) Checkpoint balancing (February 28 and September 30) in Union South and Annual balancing in Union North b) Re-establishment of DCQ based on weather normalized consumption	a) Utilities to keep their existing BGA checkpoint systems b) Enbridge to adopt MDV reestablishment mechanism
C	*COST ALLOCATION*	Incremental costing for system gas and direct purchase management	Incremental costing for system gas and direct purchase management	No Change
D	*BILLING TERMINOLOGY*	Established based on customer / market research	Established based on customer / market research	No Change
E	*IMPLEMENTATION ISSUES*			Recovery of implementation costs

GLOSSARY

PHRASE	DEFINITION
Banked Gas Account (BGA)	A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits).
BGA Management	The actions by which Direct Purchase customers make adjustments for differences between forecasted and actual consumption. Managing BGA's positions from overall debit or credit position can be accomplished using mechanisms such as; incremental deliveries ("makeup"); reducing deliveries ("suspensions"); transferring volumes to another party within the Enbridge franchise area ("title transfer"), or transferring volumes with a party in the Union Gas franchise area ("enhanced title transfer"). Customers can generally choose when and how to make BGA adjustments.
Bundled Service	A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.
Commodity Charge	A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.
Contract Demand	A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.
Curtailment	An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

PHRASE	DEFINITION
Direct Purchase	Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.
Drafting	The use of gas by a customer from the transportation or distribution system that was not provided by the customer or supported by some form of Load Balancing. Customers consuming gas in greater quantity than their deliveries (ie during winter) is known as “Drafting”. The variance is accounted for it in a BGA. The converse happens during the opposite season (summer) when customers consume less gas than what they deliver on a daily basis, so are “Packing” the system.
Electricity Day	The Electricity Day is an Ontario phenomenon and runs the same as a calendar day (ie. midnight to midnight).
EnTRAC	All gas transactions for the Company’s bundled customers are monitored and reported through the customer interactive tracking system, EnTRAC. The function of EnTRAC is similar to that of the Union Gas system, Unionline.
Firm Service	A service for continuous supply of gas without curtailment, except in exceptional circumstances.
Firm Transportation	Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.
Gas Day	The North American gas industry designates that each gas day begins at 10am eastern time and runs until that time the next day. Service providers balance supply and demand at the end of the Gas Day.
Gas Supply Charge	A charge for the gas commodity purchased by the applicant.

PHRASE	DEFINITION
Imbalance	The difference between the amount of gas that a customer has contracted for delivery in a given time period versus the amount actually consumed by the customer.
Interruptible Service	Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.
Load Balancing	The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.
Load Factor	The ratio of a customer's average consumption to their maximum consumption over a given time period.
Make-up Volume	A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.
Mean Daily Volume (MDV)	The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement. A similar arrangement also exists through Union Gas in their franchise area under the name of DCQ.
Nominations	The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.
Ontario T-Service	In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.
Overrun Gas	The amount of gas taken by a customer in excess of the Contract Demand minus any amounts curtailed.

PHRASE	DEFINITION
Pool	A grouping of one or more customers into a collective that a Customer and/or Service Provider manages gas transactions for.
Purchased Gas Variance Account (PGVA)	An account which captures the difference between the forecast of gas costs versus actual gas costs in a given year.
System Gas customers	Customers who purchase their gas supply directly from Enbridge as opposed to DP customers who make gas supply arrangements directly or through a Service Provider. A System Gas arrangement also exists through Union Gas under the name of Sales Service.
System Sales Service	A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.
T-Service	Transportation service.
Transportation Service	A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.
UFG	Unaccounted for gas.
Unbundled Service	A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.
Western T-Service	In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas.