uniongas
A Spectra Energy Company

May 26, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Re: EB-2009-0101 - Union Gas Earnings Sharing Mechanism

Dear Ms. Walli:

Please find enclosed two copies of Union's responses to May 25th undertakings. Also enclosed are the Corrected Exhibit B, Tab 3, Schedule 2, Attachment 2 and 3 which was corrected orally at the Technical Conference (TR: 53-54).

If you have any questions, please contact me at (519) 436-4521.

Yours truly,

[original signed by]

Marian Redford
Manager, Regulatory Initiatives

cc M. Penny (Torys)
EB-2009-0101 (Intervenors)

May 25, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Re: Union Gas Earnings Sharing Mechanism
(EB-2009-0101) – Union's Responses to Interrogatories

Dear Ms. Walli:

Please find enclosed two copies of Union's corrected response to Exhibit B, Tab 5, Schedule 3.

If you have any questions, please contact me at (519) 436-4521.

Yours truly,

[original signed by]

Marian Redford
Manager, Regulatory Initiatives

cc M. Penny (Torys)
EB-2009-0101 (Intervenors)

uniongas

May 21, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Re: Union Gas Earnings Sharing Mechanism (EB-2009-0101) – Union's Responses to Interrogatories

Dear Ms. Walli:

Please find enclosed two copies of Union's responses to interrogatories for the above noted proceeding.

If you have any questions, please contact me at (519) 436-4521.

Yours truly,

Marian Redford

Marian Redford
Manager, Regulatory Initiatives

cc M. Penny (Torys)
EB-2009-0101 (Intervenors)

B1 – Board Staff

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 5

Question:

Union stated that the gas distribution margin for 2008 was $24.2 million over the 2007 Board approved level; primarily this reflects increases in in-franchise contract delivery revenues of $9.9 million and increased general service revenues of $ 9.7 million offset by decreases in other cost of gas items.

a) Please confirm the amount of the decrease in the other cost of gas items and explain the reason(s) for the decrease.

Response:

a) The amount of the decrease in other cost of gas items is $8.2 million, of which $7.5 million is attributable to favourable compressor fuel, net of customer supplied fuel.

   Note that the $24.2 million of distribution margin over the 2007 Board approved level is net of the $3.6 million unbilled customer charge revenue adjustment. Please refer to the reconciliation below:

Increased In-franchise Contract Delivery Revenues	$9.9
Unbilled Customer Charge Revenue Adjustment	($3.6)
Increased General Service Revenues	$9.7
Decreased Other Cost of Gas Items	$8.2

Gas Distribution Margin 2008 Actual Increase over Board Approved	$24.2

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 6

Question:

Union stated that $4.0 million of the variance (increase) in 2008 general service revenue was due to variances in the forecasted level of customer additions, demand price elasticity related normalized average consumption ("NAC") variances, non demand side management ("DSM") related energy conservation, the Average Use ("AU") factor and the unbilled revenue accrual.

a) What portion of the $4.0 million is related to the unbilled revenue accrual?

Response:

a) The unbilled revenue accrual is $3.6 million. Please see Exhibit A, pages 12 and 13.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 9

Question:

a) Please provide the calculation that generated the 8.81% ROE.

Response:

Please see Attachment.

Formula Based Return on Equity (ROE)_Calculation

10 Year Consensus Forecast - October 2007		
3 Month		4.40%
12 Month		4.70%
Average		4.55%
Average Spread on 10 & 30 Year Canadian Bonds		0.05%
Average Long Canada - October 2007		4.60%
Adjustment factor		
Long Canada in E.B.R.O. 499	7.25%	
Average above	4.60%	
	2.65%	
25% of difference		0.66%
Risk Premium		3.55%
Formula Based ROE		8.81%

Notes

1) As per E.B.R.O 499 the risk premium was approved at 3.55% at a Long Canada of 7.25%.

2) The 10 Year Consensus Forecast is per the Consensus Forecasts as published by Consensus Economics, Inc.

3) The average spread on the 10 & 30 year Canadian Bonds rate are as reported in the Financial Post. The average is based on the October spread covering 20 days (September 17 - October 12).

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 11

Question:

Union stated that new market opportunities, in part, account for the increase in short-term transportation and exchange revenues.

a) Please describe the nature and characteristics of these new market opportunities.

Response:

Over the last number of years, end use customers have been decontracting firm long haul transportation capacity in favour of recontracting shorter term short haul transportation and commodity purchases at Dawn. This reflects in part a desire by end use customers for shorter term contracts and a lower long term transport contract commitment and related financial exposure.

The increased demand for shorter term short haul services has provided Union with the opportunity to sell increased transportation and exchange services into the market. These services are for terms as short as one day. As described in Exhibit A, Page 7 of 29, lines 10 to 15, to both respond to and support this increased market demand and provide the customer support for these transactions, Union increased its Chatham-based sales staff by two positions in 2008, refocused the contract and customer support staff and initiated process and IT systems changes. The overall objective was to capitalize on these opportunities and optimize and market Union's assets and related services.

Union also focused on further optimizing its upstream supply portfolio. Union was able to extract value from new services introduced by upstream transportation providers in excess of what was achieved historically. An example of these new services includes TCPL's Firm Transport Risk Alleviation Mechanism (FT-RAM), Storage Transportation Service Risk Alleviation Mechanism (STS-RAM), and Dawn Overrun Service – Must Nominate (DOS-MN). These new services provided increased opportunities for transportation and exchange transactions in the market. These opportunities were also influenced by favourable market conditions experienced in 2008.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 21

Question:

Union stated that a main contributor to a reduction in ROE between the 2009 forecast and 2008 actual results is an increase in DSM spending of $1.9 million.

a) Please explain why an increase in DSM spending in 2009, which was provided for in Union's 2009 rates by way of Y factor treatment, would, all else being equal, cause the 2009 ROE forecast to be less than 2008 actual?

Response:

The reference identified on page 21 is an explanation of why O&M is increasing. All else being equal the O&M increase would be offset by a rate increase, resulting in no ROE impact.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 10

Question:

a) Please provide a copy of Union's 2008 Annual Report.

b) Please provide a side-by-side comparison, with explanations for any differences, between the 2008 actuals presented in Exhibit A / Appendix B / Schedule 1 / Page 1 (i.e. column "a" of the Earnings Sharing Calculation) and the 2008 Statement of Income presented in the Annual Report.

Response:

a) Please see Attachment 1.

b) Please see Attachment 2.

Filed: 2009-04-21
EB-2009-0101
Exhibit B
Tab 1
Schedule 6
Attachment 1

union gas
A Spectra Energy Company

unionGas

Julie Dill
President

March 13, 2009

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2008 annual report. It contains Union Gas' management's discussion and analysis, consolidated financial results, statement of corporate governance and corporate directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' consolidated financial statements, management's discussion and analysis, and other filings throughout the year.

Julie Dill
President

This discussion and analysis of Union Gas Limited for the twelve months ended December 31, 2008, should be read in conjunction with the audited consolidated financial statements and accompanying notes. The terms ("we," "our", "us" and "Union Gas") as used in this report refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. The results reported herein have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in millions of Canadian dollars except where noted. Additional information relating to us, including our most recent Annual Information Form, can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis (MD&A) includes forward-looking statements. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. Many of these statements can be identified by words such as "believe", "expects", "expected", "will", "intends", "projects", "anticipates", "estimates", "continues" or similar words. We believe the expectations reflected in such statements are reasonable but no assurance is given that such expectations will be correct. All forward-looking statements are based on our beliefs and assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. In addition to other assumptions made in this MD&A, assumptions have been made in respect of:

- economic conditions in our franchise areas;
- supply and demand for natural gas;
- commodity prices;
- access to capital;
- capital expenditure estimates, plans, schedules and activities and the development, construction, operations and cost of facilities and infrastructure;
- income tax considerations;
- regulatory conditions, including decisions by the Ontario Energy Board (OEB);
- weather;
- operating risks;
- federal and provincial government policies; and
- competitive conditions.

By its nature, such forward-looking information is subject to various risks and uncertainties that are known and unknown, including those material risks discussed in the Annual Information Form and in the MD&A of Union Gas under "*Risk Factors*" which could cause our actual results and experience to differ materially from the anticipated results or other expectations expressed. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this report or otherwise, and we undertake no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

GENERAL

Union Gas' common shares are held by Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is a wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy, a Delaware corporation that is a public company in the United States of America and whose shares are listed on the New York Stock Exchange. As such, the function of an audit committee is carried out at the level of Spectra Energy during the review of its consolidated financial statements.

As a result of this corporate structure, we sought and on August 3, 2007 received an order pursuant to the provisions of the *Ontario Business Corporations Act* (OBCA) exempting us from the requirements under the OBCA to have an audit committee. In addition, securities legislation in each of the provinces in Canada provides exemptive relief from the requirement to have independent directors on a company's board of directors for entities such as Union Gas and the requirement to have an audit committee. We continue to be subject to the requirement in both the OBCA and the OEB Affiliate Relationships Code for Gas Utilities to have at least one third of our board of directors represented by independent directors.

As a result, from and after August 10, 2007, the board of directors of Union Gas is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy and there is no audit committee of the board.

Union Gas is an integrated natural gas storage, transmission and distribution company serving about 1.3 million residential, commercial and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Our distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. We also provide unregulated storage services and regulated transportation services to other utilities and energy market participants.

HIGHLIGHTS

($millions except where noted)	For the Years Ended December 31 **2008**	2007	2006
Income			
Total operating revenues	**2,130**	2,063	2,079
Earnings applicable to common shares	**175**	140	99
Dividends			
Dividends on preference shares	**5**	5	5
Dividends on common shares	**115**	36	49
Assets and long-term liabilities			
Total assets	**4,865**	4,413	4,560
Total long-term liabilities	**2,521**	2,056	2,315
Volumes of gas (10^6m^3)[1]			
Distribution volumes	**13,844**	13,878	13,207
Transportation volumes	**25,181**	23,716	20,603
Total throughput	**39,025**	37,594	33,810
Customers *(thousands)*	**1,309**	1,289	1,268
Heating degree days[2] *(degree Celsius)*			
Actual	**4,161**	3,928	3,605
Normal[3]	**4,070**	4,139	4,178

[1] 10^6m^3 equals millions of cubic meters. One cubic meter is equivalent to 35.31467 cubic feet.

[2] A heating degree day is a measure of temperature that identifies the need for heating. A degree day occurs when the average temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 heating degree days.

[3] As per OEB approved methodology used in setting rates.

RESULTS OF OPERATIONS

	For The Three Month Period Ended December 31			For The Year Ended December 31		
($millions)	2008	2007	**Increase (Decrease)**	2008	2007	**Increase (Decrease)**
Gas sales and distribution revenue	598	495	**103**	1,852	1,811	**41**
Cost of gas	422	328	**94**	1,177	1,156	**21**
Gas distribution margin	176	167	**9**	675	655	**20**
Storage and transportation revenue	70	55	**15**	244	215	**29**
Other revenue	11	10	**1**	34	37	**(3)**
Expenses	152	151	**1**	587	567	**20**
Other income	3	–	**3**	3	5	**(2)**
Interest expense	41	40	**1**	148	152	**(4)**
Income taxes	12	17	**(5)**	41	48	**(7)**
Extraordinary item	–	4	**(4)**	–	–	–
Net income	55	28	**27**	180	145	**35**
Earnings applicable to common shares	54	27	**27**	175	140	**35**

Three month period ended December 31, 2008 compared to three month period ended December 31, 2007

Gas sales and distribution revenue. The $103 million increase was primarily driven by:

- a $54 million increase from higher natural gas prices passed through to customers without a mark-up,
- a $54 million increase in customer usage of natural gas as a result of colder weather, and
- a $13 million increase due to growth in the number of customers, partially offset by
- a $17 million decrease as a result of earnings sharing under the incentive regulation framework implemented in 2008.

Cost of gas. The $94 million increase was primarily driven by:

- a $54 million increase from higher natural gas prices passed through to customers without a mark-up,
- a $47 million increase in customer usage of natural gas as a result of colder weather, and
- an $11 million increase due to growth in the number of customers, partially offset by
- a $14 million decrease related to fuel used in operations[4].

Storage and transportation revenue. The $15 million increase was primarily driven by:

- a $26 million increase due to favourable market conditions and growth of the transmission system, partially offset by
- an $11 million decrease due to an unfavourable decision from the OEB on unregulated storage revenues.

[4] Fuel used in operations includes customer supplied fuel, compressor fuel and gas measurement variances.

Income taxes. The $5 million decrease was primarily driven by an increase in deductions claimed for income tax purposes and a lower statutory tax rate. These impacts were partially offset by an increase in pre-tax income.

Extraordinary item. The $4 million decrease was primarily driven by the absence of a fourth quarter gain as a result of a 2007 adjustment to asset removal costs due to an OEB decision that effectively caused a portion of our storage operations to become unregulated.

Year ended December 31, 2008 compared to year ended December 31, 2007

Gas sales and distribution revenue. The $41 million increase was primarily driven by:

- a $47 million increase due to growth in the number of customers,
- a $31 million increase in customer usage of natural gas due to colder weather, partially offset by
- a $20 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $17 million decrease as a result of earnings sharing under the incentive regulation framework implemented in 2008.

Cost of gas. The $21 million increase was primarily driven by:

- a $44 million increase due to growth in the number of customers, and
- a $25 million increase in customer usage of natural gas due to colder weather, partially offset by
- a $23 million decrease related to fuel used in operations, and
- a $20 million decrease from lower natural gas prices passed through to customers without a mark-up.

Storage and transportation revenue. The $29 million increase was primarily driven by:

- a $59 million increase primarily due to favourable market conditions and growth of the transmission system, partially offset by
- a $30 million decrease due to an unfavourable decision from the OEB on the accounting for unregulated storage revenues in the second quarter of 2008.

Expenses. The $20 million increase was primarily driven by:

- a $12 million increase in depreciation and amortization due to a higher asset base resulting primarily from completion of Phase II of the Dawn-Trafalgar expansion,
- a $9 million increase in costs related to consumer conservation efforts which are recovered in rates, and
- an $8 million increase in salaries and wages, partially offset by
- a $6 million decrease in employee future benefit costs.

Income taxes. The $7 million decrease was primarily driven by an increase in deductions claimed for income tax purposes and a lower statutory tax rate. These impacts were partially offset by an increase in pre-tax income.

QUARTERLY RESULTS

($millions)	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Gas sales and distribution revenue	771	329	216	495	733	299	222	598
Storage and transportation revenue	56	50	54	55	64	48	62	70
Other revenue	9	10	8	10	7	8	8	11
Total operating revenues	836	389	278	560	804	355	292	679
Net income	96	18	3	28	101	22	2	55
Net earnings applicable to common shares	95	16	2	27	100	20	1	54

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas, resulting in no impact to net income.

RATE REGULATION

Union Gas is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act* (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Distribution Rates

In November 2006, the OEB issued a decision on the regulation of rates for gas storage services in Ontario (Storage Forbearance Decision). As a result of its finding that the market for storage services is competitive, the OEB does not regulate the rates for storage services to ex-franchise customers[5] or the rates for new storage services to in-franchise customers[6]. Existing storage services to in-franchise customers will continue to be provided at cost-based rates. The decision creates an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

In June 2007, four parties petitioned the Lieutenant Governor in Council (LGIC) of Ontario to direct the OEB to review and change the Storage Forbearance Decision. Submissions to the LGIC on these petitions from other parties, including Union Gas, were made at the end of July 2007. The four petitioning parties filed responses to those submissions in mid-August 2007. The LGIC considered the petitions and confirmed the OEB's decision in April 2008.

[5] Ex-franchise customers refer to those customers that are not served directly through our facilities and generally are market participants such as marketers, other utilities and power customers served by other utilities.
[6] In-franchise customers refer to those customers that are within our franchise area and served through our facilities.

Non-Commodity Deferral Account Disposition

In March 2008, we applied to the OEB for the annual disposition of our 2007 non-commodity deferral account balances. With respect to the treatment of the long-term storage deferral account, we recorded net revenues associated with market priced long-term storage contracts entered into prior to the OEB's November 2006 decision to forbear from regulating ex-franchise storage services for sharing with ratepayers. All net long-term storage revenues related to contracts entered into after November 2006 were recorded to the sole account of Union Gas.

In June 2008, the OEB issued a decision that requires us to record in the long-term storage deferral account all net revenues associated with long-term storage contracts for sharing with ratepayers, including those entered into after November 2006. We have adjusted our financial records accordingly. In June 2008, we filed a motion with the OEB to review its decision, as it was our view that the decision was inconsistent with past OEB decisions. The OEB heard our motion by way of written proceeding in the third quarter of 2008. In October, the OEB issued a decision that denied our appeal.

Incentive Regulation

Our rates, effective January 1, 2008 are set under a multi-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The incentive regulation framework allows for annual inflationary rate increases, offset by a productivity factor of 1.82% that is fixed for each of the next five years. The framework also allows for rate increases in the small volume customer classes where average use is declining, a five-year term, certain adjustments to base rates, the continued pass-through of gas commodity, upstream transportation and demand side management costs, an allowance for unexpected cost changes that are outside of management's control, earnings sharing between Union Gas and our ratepayers beyond specified earnings levels and equal sharing of income tax changes between Union Gas and ratepayers.

Under the incentive regulation framework, 2008 rates for most small volume customers increased by less than 2%, and the rates for large volume customers increased by less than 1%.

In September 2008, we filed an application with the OEB seeking approval of 2009 regulated distribution, storage and transmission rates, determined pursuant to the incentive regulation framework. A decision was received in January 2009 and will be applied retroactively to the beginning of the year as of April 1, 2009. The rate change is a slight increase for small volume customers and a slight decrease for large volume customers.

Natural Gas Risk Management Contracts

In the incentive regulation framework decision, the OEB found that there is no material net benefit to our customers of financially hedging our natural gas commodity costs, and disallowed the recovery of the costs associated with the risk management program that were previously embedded in distribution rates. In September 2008, we exited all remaining financial positions and ceased all financial hedging activity. The financial impact of the discontinuance of our commodity risk management program did not have a material impact on our consolidated financial statements.

Storage Allocation Proceeding

In August 2007, the OEB initiated a proceeding to address the outstanding matters on storage allocation identified in its decision to forbear from regulating certain gas storage services. The outstanding matters included the appropriate storage allocation methodology for in-franchise customers who do not have seasonal load balancing requirements and the pricing of high deliverability storage services for in-franchise customers.

The hearing concluded with an OEB decision in April 2008, approving storage allocation methodologies that meet the reasonable needs of in-franchise customers with and without seasonal load balancing requirements. Market prices will apply to storage services in excess of the amount allocated using the approved allocation methods.

Commodity Rates

Union Gas and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis (Quarterly Rate Adjustment Mechanism), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent twelve months and are also subject to review and approval by the OEB on an annual basis. This allows us to adjust customer rates closer to the time of incurrence.

The OEB is currently conducting a review of the Quarterly Rate Adjustment Mechanism for the Ontario natural gas utilities. A decision is expected during 2009. No material impact is expected to result from this decision.

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities. We do not invest in asset-backed commercial paper.

We meet our short-term cash requirements through funds generated from operations, issuance of short-term debt and access to our lines of credit. Long-term capital requirements are met through the combination of cash flow from operations, issuance of long-term debt, preference shares, and common equity investment by our parent company.

Changes in Cash Flow

($millions)	**2008**	2007
Operating activities	**162**	299
Investing activities	**(404)**	(380)
Financing activities	**242**	(28)

Operating Activities

Typically, the primary factors impacting cash flow from operations are collections of accounts receivable balances, changes to inventory balances and payments for gas purchases and for amounts owing to suppliers and marketers. Fluctuations in weather, commodity rates, and gas prices, as well as the timing of cost recovery in regulated rates, directly impact cash flows from operations.

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn from throughout the heating season. Inventory levels decrease from December and thus contribute to a positive cash flow from operations during the first quarter. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Many of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically have used more gas than has been delivered to us and we have collected cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

Cash flow provided by operating activities was $162 million and $299 million for 2008 and 2007, respectively. The $137 million decrease in cash provided by operating activities in 2008 compared to 2007 is primarily due to increased gas volumes purchased in 2008 compared to 2007. These were partially offset by a decrease in income tax payments related to a first quarter 2007 payment of 2006 tax liabilities.

Cash flow provided by operating activities for the three months ended December 31, 2008 was $48 million compared to $88 million for the same period ended December 31, 2007. The decrease in cash provided by operating activities is primarily due to increased gas volumes purchased and normal seasonal trends.

Investing Activities

The table below is a summary of capital expenditures:

	2009	2008	2007
	(estimated)		
Storage and transmission projects	44%	55%	52%
Distribution	46%	38%	25%
General equipment	10%	7%	23%
	100%	100%	100%
Total capital expenditure ($millions)	$285	$404	$373

The table below is a summary of capital project type:

	2009	2008	2007
	(estimated)		
Maintenance projects[7]	81%	57%	51%
Expansion projects	19%	43%	49%
	100%	100%	100%

Capital investments are necessary to meet the growth in customer demand for services and are funded through a combination of cash flow from operations and debt facilities.

Maintenance expenditures in 2009 are expected to be consistent with the 2008 level of spending. Expansion expenditures for 2009 are expected to be significantly lower as compared to 2008 due primarily to the significant expansion projects that came into service in 2008 or early 2009 relative to planned spending in 2009 on new projects. The 2009 expansion capital expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Based on our current assessment, we believe that expansion opportunities will continue to exist in the future.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2009 projects will be done through a combination of cash generated from operations and available debt facilities.

Financing Activities

We have the following financing arrangements in place:

- A new shelf prospectus was filed in August 2008 replacing one that was due to expire during that month. The new shelf prospectus permits the issuance of medium-term notes, in one or more series, up to an aggregate principal amount of $700 million and for terms of up to 30 years with maturities of not less than one year from the date of issue. The shelf will expire in September 2010. As of December 31, 2008, $400 million was available.
- Union Gas has a $500 million committed credit facility available to help meet its short-term financing needs. As of December 31, 2008, $294 million was available.
- Union Gas has a $25 million operating facility available to help meet its short-term financing needs. As of December 31, 2008, $23 million was available.

In April 2008, we issued $200 million of medium-term notes at 5.35% per annum, due April 27, 2018.

In July 2008, we retired, at par, $100 million of medium-term notes at 5.70% per annum.

In July 2008, we made a repayment of $3 million on a 10.75% 1989 Senior sinking fund debenture.

In September 2008, we issued $300 million of medium-term notes at 6.05% per annum, due September 2, 2038.

In October 2008, we made a repayment of $4 million on an 11.55% 1988 Series II sinking fund debenture.

On January 1, 2009, all of the holders of the 4.79% Cumulative Redeemable Convertible Class B Preference Shares, Series 11 (Series 11 Shares) exercised their option to convert their shares back into

[7] Maintenance projects include costs incurred for new customer attachments. For 2009, maintenance projects also include expansion capital for in-franchise customers.

Cumulative Redeemable Convertible Class B Preference Shares, Series 10 (Series 10 Shares). Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. On January 1, 2014, holders of Series 10 Shares have the right at their option, to convert all or any of the Series 10 Shares into Series 11 Shares. The dividend rate on the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

The indentures and agreements relating to our long-term debt obligations contain covenants limiting the payment of dividends. Certain debenture issues limit the payment of dividends such that dividends are not permitted, with certain exceptions, if immediately thereafter all indebtedness for money borrowed would exceed 75% of the total capitalization of Union Gas. We are in compliance with these provisions.

Our $500 million committed credit facility expires in July 2012 and includes a provision which requires us to repay all borrowings under the facility for a period of two days during the second quarter of each year. This facility is intended to be used primarily to manage the significant seasonal changes in working capital experienced by Union Gas as a result of natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate.

Our short-term borrowing levels fluctuate significantly during the year due to the funding of construction activities, the timing of long-term debt issues, maturities, other financing activities, and the seasonality of our business. Our 2008 short-term borrowings peaked in December at approximately $206 million.

During 2006, the OEB approved an increase in the common equity component of our capital structure from 35% to 36% effective January 1, 2007. In order to maintain the common equity component of the capital structure at the level no greater than that approved by the OEB, we have typically paid a quarterly dividend to our parent company. During the fourth quarter of 2006, we suspended dividend payments to allow the common equity component to increase to the allowed 36%. We resumed payment of the quarterly common dividend during the fourth quarter of 2007. During 2008, we paid a quarterly dividend to our parent of approximately $16 million as well as an additional $50 million dividend to our parent during the fourth quarter of 2008.

During 2008, as part of a new corporate legal structure we received Board of Director approval to initiate the redemption of all preference shares we have issued and outstanding. We have since decided not to proceed with the proposed preference share redemption.

FINANCIAL CONDITION

Ratings Summary

	Standard & Poor's (S&P)	**Dominion Bond Rating Service (DBRS)**
Commercial paper	A – 2	R – 1 (low)
Debentures	BBB+	A
Preferred shares	P – 2 (low)	Pfd – 2

Our credit ratings remain unchanged from those reported in the 2007 Annual Report.

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2009	2010-2011	2012-2013	Thereafter
Long-term debt	2,240	28	472	–	1,740
Redeemable preference shares	5	–	–	–	5
Capital lease obligations	1	1	–	–	–
Operating leases	27	5	11	10	1
Purchase obligations[8]	1,184	724	179	140	141
Environmental obligations[9]	61	1	9	41	10
Contributions to employee future benefit plan[10]	206	37	82	87	–
Total contractual obligations[11]	3,724	796	753	278	1,897

RELATED PARTY TRANSACTIONS

We purchase gas and transportation services at prevailing market prices and under normal trade terms from commonly controlled companies. During the year ended December 31, 2008, these purchases totalled $1 million (2007 - $1 million). Union Gas may also provide storage and transportation services to commonly controlled companies under normal trade terms. Storage and transportation services provided to commonly controlled Spectra Energy companies totalled less than $1 million during 2008 (2007 – less than $1 million).

We provided administrative, management and other services to commonly controlled companies totalling $8 million (2007 – $7 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $6 million (2007 – $6 million).

At December 31, 2008 we have intercompany receivable balances of $2 million (2007 – $3 million) and intercompany payable balances of $6 million (2007 – $1 million), which are recorded in accounts receivable and accounts payable, respectively.

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[8] Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; includes contractual obligations to purchase physical quantities of natural gas; and includes contracts for software and consulting or advisory services. Amounts also include contractual obligations for engineering, procurement and construction costs for pipeline projects.

[9] Includes capital, operating and maintenance expenditures required under the comprehensive certificate of approval.

[10] Contributions to employee future benefit plans beyond 2009 are based on actuarial estimates and assumptions. The impact of any change in these estimates and assumptions could result in contributions that differ significantly from the amounts disclosed.

[11] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation and self-insurance claims, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude future income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year

During 2008, we obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2008 was a $115 million payable (2007 – $104 million payable). These loans are classified as short-term borrowings in 2008. Interest received on these loans during 2008 totalled less than $1 million (2007 – no interest received) and interest paid on these loans totalled $2 million in 2008 (2007 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

GAS SUPPLY

The gas supply portfolio of Union Gas includes both fixed price contracts and contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are primarily indexed to either the New York Mercantile Exchange natural gas futures contracts or the Canadian Gas Price Reporter that publishes Alberta index prices.

We previously engaged in financial hedging activity for the purpose of managing the risk associated with market fluctuations in the price of natural gas. However, a July 2008 OEB decision found that there is no material net benefit to our customers of financially hedging our natural gas commodity costs, and disallowed the recovery of the costs associated with the risk management program that were previously embedded in distribution rates. In September 2008, we exited all remaining financial positions and ceased all financial hedging activity. The financial impact of the discontinuance of our commodity risk management program did not have a material impact on our consolidated financial statements.

Gas costs are included in customer rates based on forecasted gas supply approved by the OEB. Differences between the OEB approved reference prices and the actual cost of gas purchased, including the impact of the indexed purchase prices, are recovered from or refunded to customers through the quarterly rate adjustment mechanism and subsequently reviewed and approved by the OEB on an annual basis.

OUTLOOK

The Economy

Union Gas expects an adverse financial impact from the declining Canadian and U.S. economies, tightening access to capital and credit markets, high levels of consumer and government debt and high government deficit levels.

Gas Sales and Distribution

Natural gas prices exhibited significant volatility in 2008 with record high natural gas prices experienced during the summer and a subsequent decline by approximately 50% from these record high levels. Natural gas pricing continues to be influenced by world oil pricing, stronger domestic supply growth in North America and the overall status of the economy. While year-end 2008 natural gas prices were relatively low and are projected to remain low for 2009, the decline in economic growth and the global financial crisis are expected to negatively impact customer growth and existing customer consumption in the residential, small commercial and small and large industrial markets in 2009. These impacts may also result in the continued trend of temporary and permanent plant closures, particularly in the manufacturing sector. It is unclear to what extent the Federal and Ontario Provincial government stimulus packages will mitigate any of these impacts.

Union Gas is also experiencing a reduction in distribution throughput as a result of energy conservation including our Demand Side Management (DSM) initiatives, declining normalized use per customer and a general trend toward warmer weather. We expect these trends to continue. In addition, the Ontario Ministry of Energy has committed to aggressively promoting a culture of conservation across the province that is expected to further reduce energy consumption, with corresponding impacts on our volume-based revenue.

Union Gas continues to support focused efforts to promote conservation and energy efficiency through our DSM programs. In 2008, we spent $20 million (2007 - $17 million) promoting these programs. Further, in response to the poor economic conditions, actual and potential job losses and business closures, and the continued volatility of natural gas commodity prices, we expect customers to continue to focus on reducing gas consumption by increasing investments in energy efficiency and conservation. However, access to capital may also negatively impact potential large scale customer DSM projects which while being economically prudent, may be delayed until the easing of the credit markets.

Consumer concern over the reliability of electricity supply may create an opportunity to increase the penetration of natural gas appliances such as fireplaces, clothes dryers, ranges and grills in the residential market. Further, changes in the electricity market may also create a renewed interest in natural gas fired "stand by" generation, where that generating capacity is only required in unexpected circumstances.

Storage and Transportation (S&T)

The continental S&T marketplace is being impacted by the global economic downturn. Weak commodity prices and narrow seasonal price spreads combined with higher financing costs in the marketplace are expected to put continued downward pressure on the value of unregulated storage services in 2009. In addition, we have seen and expect to see a contraction in our storage and transportation customer base as a result of the weakness and restructuring occurring within the financial services industry.

Although our customer base is expected to decline as a result of the current economy, management expects overall demand for natural gas in North America to grow at a long-term rate of one percent per year along with continued growth in peak day demands. However, given the current economic conditions, management expects that demands will be reduced in 2009 and 2010. The extent of these demand reductions is dependent on the length and extent of the current economic downturn.

Additional S&T infrastructure continues to be required to bring new sources of gas supply to market. The location of our S&T facilities, with interconnections between major U.S. markets in the Great Lakes region and the U.S. Northeast supports growth opportunities for us. However, given the current economic downturn, management expects that some growth opportunities will be delayed.

In early June 2008, the construction of the compressor station, wells and pipelines related to the development of the Tipperary North and South storage reservoirs was completed. Storage injections commenced in early June 2008. Performance of the reservoirs is being assessed during the first operating cycle and initial results suggest the need for additional wells. These additional wells were anticipated as part of the planned capital expenditure for this development and will be pursued in 2009.

Two expansion projects originally expected to be completed during 2008 were completed in January 2009. During January 2009, we completed the construction of new 2008 transmission capacity, and completed and commissioned the 2008 Dawn storage deliverability expansion. Delays in the receipt of compression equipment and related components from the primary supplier created unanticipated delays in the projects. Union Gas pursued commercial market remedies in order to manage the impact of these delays on service commitments to customers. The cost and revenue impacts of these remedies did not have a material impact on our consolidated financial statements.

We conducted an open season[12] during the July to September, 2008 period to solicit market interest for transmission service on the Dawn-Trafalgar transmission system and targeted an in-service date for a proposed expansion in the fourth quarter of 2010. As a result of the delays experienced with our 2008 expansion projects and given the current economic circumstances, we expect to pursue this expansion to service these new demands in 2011.

Environmental, Health and Safety

During 2008, we obtained approval from the Ontario Ministry of the Environment (MOE) for a multi-site comprehensive certificate of approval (CC of A) for the permitting of our air and noise emission sources. The CC of A will treat Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit. The terms and conditions of the CC of A include significant financial obligations for capital, operating and maintenance expenditures over a period of approximately 10 years, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the expected terms of the CC of A, we will be allowed to add and modify facilities without prior approval from the MOE, thereby reducing the risk of delays associated with obtaining environmental permits.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and earnings level may be adversely affected by a number of risks as described below.

Market Risk

Sales to industrial customers are affected by general economic conditions and the absolute and relative price of alternative energy sources. In 2009, we expect that the continued volatility of energy prices, the serious decline in the North American economy, and the competitive position of oil relative to natural gas are significant risks that we will seek to manage.

Our industrial markets continue to experience a significant amount of demand reduction related to plant closures and energy efficiencies resulting in permanent demand losses.

The risk of bad debt exposures is expected to increase significantly across all markets in 2009 and 2010 as a result of the economic downturn. Our bad debt exposure consists of both the risk of collecting receivables for services provided as well as the risk related to gas imbalances that occur as a regular part of the services provided to the direct purchase market.

Sales to Union Gas' residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates, the preference for natural gas products and services, and the continued shift to higher efficiency products. New customer additions are expected to soften substantially in 2009 from 2008 levels. In 2009, the ongoing trend towards more energy efficient products will continue to put pressure on Union Gas' normalized average usage. Further, the current trend toward owning a water heater versus rental options exerts pressure on our market share, as the initial cost to purchase an electric water heater is less than the cost of a gas water heater.

[12] An open season is a process by which asset developers solicit expressions of interest from parties who may be interested in contracting use of that asset.

Sales to ex-franchise storage and transportation customers can be affected by the expiry of existing long-term contracts. A significant quantity of transportation capacity is now subject to renewal on an annual basis. Customers with capacity expiring in 2011 are required to provide notice of their intent to re-contract for the expiring capacity in 2009. Union Gas' standard contract terms and conditions result in transportation customer contracts automatically renewing after the initial term for one year at a time subject to the customer providing two years prior notice of termination. For storage contracts, our standard contract terms do not allow for renewals but will typically have contract terms of one to five years. Union manages the portfolio of expiring contracts each year and sells the expired capacity back into the market.

The ex-franchise storage and transportation market is being impacted by the current economic downturn. Weak commodity prices and seasonal pricing spreads combined with higher financing costs in the marketplace may put continued downward pressure on the value of unregulated storage services in 2009. Further, there is a risk of continued contraction in the storage and transportation customer base as a result of the weakness and restructuring occurring within the financial services industry.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy includes both fixed and variable price contracts. Union Gas is no longer engaged in financial risk management as a result of a July 2008 OEB decision. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers.

Credit Risk

Credit risk represents the loss that we could incur if a customer fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2008 was $69 million (2007 - $59 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

The current economic downturn and credit crisis will increase credit risk and related exposures across all markets in 2009.

Weather Risk

The revenue levels approved by the OEB are impacted by weather, as a primary component of Union Gas rates is volume based. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 55:45 weighting of the 30-year average forecast and 20-year trend forecast respectively, for 2008 and beyond. Since a large portion of the gas distributed to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and on our financial results.

Regulatory Risk

Union Gas' allowed return on equity (ROE) is formula-based and is periodically established by the OEB. The allowed ROE of 8.54% was established and incorporated into our approved rates in 2007 and will remain unchanged throughout the 5-year incentive regulation period (2008-2012). This level is well below the allowed returns for U.S. gas utilities, and there are no apparent fundamental differences between Union Gas and those U.S. utilities that would account for a significant ROE gap. This level is also inconsistent with the increasing cost of capital caused by the current credit crisis and economic downturn. We are increasingly concerned that our ability to attract new equity capital will be compromised without a change in regulatory policy respecting the allowed ROE in Ontario.

Union Gas' incentive regulation framework includes a provision for a review of the pricing mechanism contained in that framework. The review is triggered if there is a variance of 3% or more between Union's actual utility ROE as normalized for weather and the utility ROE determined by the application of the OEB's ROE formula. For 2008, the utility ROE determined by the OEB's ROE formula is 8.81%. As a result, the review thresholds for 2008 are 5.81% and 11.81%. Our normalized utility ROE for 2008 exceeded the upper review threshold. Accordingly, we will be required to apply to the OEB during 2009 for a review of our incentive regulation mechanism. Any substantial change to the incentive regulation parameters could materially affect our future earnings, capital investments, employment levels, access to new long-term debt, cash flows and financial position, as well as our ability to manage the impacts related to the economic downturn and financial credit crisis in 2009 and 2010.

Competition

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of our facilities even within our distribution franchise area may be permitted. In addition, other companies could enter our markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

In November 2006, the OEB issued a decision on the regulation of rates for gas storage services in Ontario. As a result of its finding that the market for storage services is competitive, the OEB will not regulate the rates for storage services to ex-franchise customers or the rates for new storage services to in-franchise customers subject to a four year transition period beginning in 2008. Existing storage services to in-franchise customers will continue to be provided at cost-based rates. The decision creates an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

Permit Fees

Effective January 1, 2007, the Government of Ontario granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. We are unable to determine with certainty the costs associated with such a change as they depend on the number of municipalities that proceed to implement a permit fee and the amount of any such fee. As Union Gas accesses its pipelines tens of thousands of times annually even a modest fee may have a significant impact. During 2008, permit fees levied by municipalities against Union Gas did not have a significant impact on our consolidated financial statements. Should more municipalities start implementing a permit fee or if the amounts increase and these assessments become significant in the future, Union Gas will apply to the OEB to recover the annual cost of these fees in rates.

Financing Risk

Union Gas is subject to long-term debt covenants that include requirements for specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the level of new long-term debt available to Union Gas.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent an emerging issue that must be addressed by Union Gas. We must maintain our ability to attract, train, and retain employees with the requisite skills and capabilities to operate in the complex and competitive energy industry.

Performance Risk

We have extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies, and others. The risk of non-performance by a contracting party may be analyzed and reduced but it cannot be entirely eliminated. Ongoing consolidation of customers, financial institutions and partners may increase the severity of a default.

Insurance Risk

While Union Gas maintains insurance against exposures to losses associated with transportation, distribution and storage of natural gas, the occurrence of a significant event against which we may not be fully insured could have an adverse effect on our business.

Interest Rate Risk

Our business is capital intensive and as a result often requires financing. Significant movements in interest rates may expose Union Gas to higher borrowing costs. Interest rates are also a key factor in the pension cost assumptions. Significant movements in interest rates will impact earnings.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our consolidated financial statements.

Facility Risk

We carry on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

The Ontario Power Authority (OPA) is the organization responsible for the long-term planning for Ontario's electricity system. The OPA has determined that demand for electricity is expected to grow over the next 20 years. Over that same period, most of the nuclear plants will reach the end of their useful lives, where those nuclear plants currently produce approximately 50% of Ontario's electricity. Also, the Ontario government has committed to close all of the coal-fired generating plants in the province by 2014 in order to reduce air emissions and their attendant health impacts, where those plants currently produce approximately 20% of Ontario's electricity. These circumstances combine to create a forecast shortfall in electricity supply of approximately 24,000 MW of Ontario's current capacity. These circumstances also create greater likelihood for government intervention in the provincial energy sector, some of which may affect Union Gas.

The Ontario government has committed to develop programs that provide greater assistance to low-income consumers. This commitment may result in different rate levels, security deposit policies, service shut-off policies and other changes for low-income natural gas consumers. Any such changes may affect Union Gas.

Construction Risk

Union Gas continues to experience significant cost increases related to material, labour and third party contractor costs associated with new capital expansion projects. These cost increases are related to the strong growth in infrastructure projects across North America and may create economic circumstances whereby we are unable to economically pursue new infrastructure investments in Ontario. Further, current economic circumstances may impact the material and resources required to pursue new capital expansion projects.

Environmental, Health and Safety Risk

Union Gas highly values the health and safety of its employees, customers and communities. Protecting and responsibly managing natural resources are critical to the quality of life in the areas that we serve, the environment and our long-term business success. We have continued our implementation of an environment, health and safety management system to ensure continued compliance with applicable regulations and to provide a consistent approach to policies, programs and procedures.

The production, transmission, delivery and consumption of energy all have potential for associated environment, health and safety impacts. There are a variety of hazards and operating risks inherent in natural gas transmission and storage and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution, and impairment of operations, any of which could result in substantial losses to Union Gas. For pipeline and storage assets located near populated areas, including residential areas, commercial business centres, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. As a result, these activities are subject to a comprehensive framework of federal, provincial and local laws, regulations and guidelines. We actively engage with government and other stakeholders to affect the development of this regulatory framework. Union Gas does not maintain insurance coverage against all of these risks and losses, and any insurance coverage it might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings and financial condition.

Policymakers at regional, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global greenhouse gas emissions in the effort to address the challenge of climate change. It is likely that our assets and operations in Ontario will become subject to the direct and indirect effects of current and possible future global climate change regulatory actions.

While Canada is a signatory to the United Nations-sponsored Kyoto Protocol, which prescribes specific targets to reduce greenhouse gas (GHG) emissions for developed countries for the 2008-2012 period, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the federal government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. The framework requires GHG emissions intensity reductions of 18% beginning in 2010, with further reductions of 2% per year thereafter. Regulatory design details from the Government of Canada associated with the framework remain forthcoming. We expect a number of our assets and operations to be affected by pending federal climate change regulations but the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

A number of states in the U.S. and some Canadian provinces are establishing or considering regional programs that could mandate reductions in GHG emissions. This includes the Western Climate Initiative (WCI) which includes a number of Western states and the provinces of British Columbia, Ontario, and Quebec. We expect a number of our assets and operations could be affected either directly or indirectly by the WCI. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

As Canadian federal and provincial policies remain largely under development, we cannot estimate the potential effect of GHG policies on our future consolidated financial statements. We continue to monitor the development of GHG regulatory policies. We cannot estimate with certainty the potential effect of the Canadian GHG and air pollutant reduction policies currently under development on our future consolidated financial statements due to the uncertainty of the Canadian policies.

Franchise Rights

Union Gas has 266 franchise agreements with 228 municipalities in Ontario. These agreements set out the terms and conditions under which we conduct our business on municipal roadways.

To date, we have successfully renewed 144 franchise agreements under the 2000 Model Franchise Agreement. We expect the OEB will to continue to approve additional franchise agreements under this model during 2009.

CONTINGENCIES

In 2004, Union Gas was served with two class action claims, seeking relief similar to a case filed against Enbridge Gas Distribution (Enbridge). In 1994, Enbridge, a gas distribution company located in Toronto, Ontario was served with a class action claim seeking, among other things, a declaration that the OEB-approved 5% late payment fee paid by Enbridge's customers since 1981 is interest that exceeds the amount permitted by the Criminal Code of Canada, and that by collecting the late payment fee, Enbridge had been unjustly enriched and those who paid the fee should be entitled to restitution. In December 2006 the court approved settlement of the claim commenced against Enbridge for $22 million, including $11 million in legal fees and expenses, $2 million to be paid to the Class Proceedings Fund (operated by the Law Foundation of Ontario) and a $9 million donation to the Winter Warmth Fund. In February 2008, Enbridge received OEB approval to recover the full cost of the settlement plus interest and the related legal costs from ratepayers over a five year period. In May 2008, the representative plaintiff in the

Enbridge claim filed a petition requesting a review of the OEB rate recovery decision. In December 2008, the Lieutenant Governor in Council denied the request and the decision of the OEB was confirmed.

By the date that we were served with the two class action claims, the structure of the OEB-approved late payment fees charged by us had changed from the 5% structure which was the subject of the two Supreme Court of Canada decisions. We have calculated the total amount of 5% late payment fees collected since 1994 to be up to $77 million.

In February 2009, the court dismissed one of the class action claims commenced against us and approved settlement of the other class action claim. The amount of the settlement is a total of approximately $9 million, including approximately $3 million in legal fees, disbursements and other expenses, less than $1 million that will be paid to the Class Proceedings fund (operated by the Law Foundation of Ontario) and approximately $5 million to be paid in three equal, annual instalments to the Winter Warmth Fund as administered by the United Way. We will be seeking OEB approval in the future to recover the full cost of the settlement plus interest and the related legal costs from ratepayers, however, we cannot provide assurance that we will be successful in the recovery.

OUTSTANDING SHARES

	2008	2007
Redeemable Preferred Shares		
Class A, Series A, 5.5%	47,672	47,672
Class A, Series C, 5.0%	49,500	49,500
Preferred Shares		
Class A, Series B, 6.0%	90,000	90,000
Class B, Series 11, 4.79%	4,000,000	4,000,000
Common Shares	57,822,650	57,822,650

On January 1, 2009, all of the holders of the Cumulative Redeemable Convertible Class B Preference Shares, Series 11 (Series 11 Shares) exercised their option to convert their shares back into 4.88% Cumulative Redeemable Convertible Class B Preference Shares, Series 10 (Series 10 Shares). Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. On January 1, 2014, holders of Series 10 Shares have the right at their option, to convert all or any of the Series 10 Shares into Series 11 Shares. The dividend rate on the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

In February 2009, all of the common shares of Union Gas were transferred to Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast.

CERTIFICATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures are controls and other procedures that are designed to: (a) provide reasonable assurance that material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2008, and, based upon this evaluation, the President and Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by the Companion Policy 52-109CP to National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, with the participation of our President and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by the Companion Policy 52-109CP to National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

The Company's Board of Directors reviewed and approved the 2008 audited consolidated financial statements and this management's discussion and analysis prior to its release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board of Directors.

Regulatory Accounting

Union Gas follows Canadian GAAP, which allows accounting treatments that may differ for rate-regulated operations from those otherwise expected in non rate-regulated businesses. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to ratepayers. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other rate-regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be required to be recognized in current period earnings.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and cost of gas are recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2008 was $192 million (2007 – $125 million). Differences between actual and estimated unbilled revenues are not material to net income. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2008 $145 million (2007 – $85 million) was included in unbilled revenue for the cost of natural gas.

Employee Future Benefits

The Company provides employees with a choice between defined benefit and defined contribution pension plans. The Company's costs of providing defined benefit pensions are dependent upon a number of factors, including: rates of return on pension fund assets, discount rates and interest rates used to measure the required minimum funding requirements of the plans in accordance with pension legislation, future changes in government regulations and the Company's required or voluntary contributions to the plans. Without sustained growth in the pension fund investments over time to increase the value of the pension fund assets, and depending upon the other factors impacting the Company's costs, as listed above, the Company may be required to fund the plans with significant additional cash contributions. Such additional cash funding contributions could have a material impact on the Company's future earnings and cash flows.

The assets of the Company's defined benefit pension plans are invested approximately 60% in equities and 40% in bonds. The significant decline in capital markets during 2008 resulted in investment related losses of approximately $120 million. In the absence of any future offsetting experience asset gains, the Company will be required to make additional cash contributions to fund these investment related losses.

Based on current regulations, the additional cash contributions resulting from the 2008 investment related losses are anticipated to be approximately:

($millions)	2009	2010	2011	2012	2013 & Thereafter
Additional cash contributions required	$10	$10	$25	$25	$55

In the absence of future experience gains, the investment related losses will result in increases in the annual cost of pensions recognized in the Company's financial statements. The increase in the annual cost of pensions is expected to be approximately $4 million in 2009 and approximately $15 million in 2010 and each subsequent year through 2020.

Critical estimates and assumptions are required to account for employee future benefits, and changes to these estimates and assumptions could result in a material difference to our employee future benefit plan obligation. The following is a summary of the sensitivity of key assumptions used to record the employee future benefit liability:

Sensitivity of key assumptions ($millions)

	Registered Pension Plan and Supplemental Pension Arrangements		Post-Retirement Benefits Other than Pensions	
Assumed change in:	1% Increase	1% Decrease	1% Increase	1% Decrease
Discount rate				
Change in 2008 net periodic benefit cost	(6)	7	–	–
Change in benefit obligation	(67)	75	(6)	7
Health care cost trend rate				
Change in benefit obligation	–	–	5	(4)
Expected rate of return on assets				
Change in 2008 net periodic benefit cost	(5)	5	–	–

The discount rates used to calculate the employee future benefit plan's obligations increased approximately 0.5% between September 30 and December 31, 2008.

FUTURE ACCOUNTING CHANGES

Rate-regulated Operations

Effective January 1, 2009, amendments have been made to certain sections of the Canadian Institute of Chartered Accountants (CICA) Handbook related to rate-regulated accounting.

CICA Section 3465, Income Taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. This amendment also requires that a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a pre-tax basis in the financial statements. The impact of these changes resulted in an increase in regulatory assets and an increase in future income tax liabilities of approximately $273 million on January 1, 2009.

CICA Section 1100, Generally Accepted Accounting Principles has been amended to remove a temporary exemption pertaining to the application of the recognition and measurement of assets and liabilities arising from rate regulation. In the absence of specific guidance the CICA has permitted reliance on an other source of GAAP, specifically the Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). FAS 143 requires asset removal costs, currently included in property, plant and equipment, to be reported as a regulatory liability. The impact of these changes resulted in an increase in property plant and equipment and an increase in regulatory liabilities of approximately $402 million on January 1, 2009.

Goodwill

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing both Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, we will adopt the new standards for our fiscal year beginning January 1, 2009. The new section establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recording by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The impact of these changes did not have a material impact on our consolidated financial statements.

Transition to International Financial Reporting Standards (IFRS)

On February 13, 2008, the Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

Conversion plan

Our IFRS conversion project started in 2007. We have established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management. Regular reporting is provided to certain senior executives and to our Board of Directors. We have also engaged an external advisor to assist with our conversion to IFRS.

Our project consists of four phases: diagnostic; design and planning; solution development; and implementation. We have completed the diagnostic, design and planning phases, which involved a high level review of the major differences between current Canadian GAAP and IFRS as they currently stand.

We are in the solution development and implementation phases of our project. We have documented the areas of key accounting differences with high potential impact to us and are now making policy recommendations and beginning implementation steps in the identified areas. We have established a communication plan, commenced our training programs and are evaluating the impacts of IFRS transition on other business activities.

Key accounting differences

We have determined that the areas of key accounting differences with high potential impact are rate-regulated accounting, accounting for employee future benefit costs and accounting for property, plant and equipment, as well as the initial adoption of IFRS under the provisions of IFRS 1, First-time Adoption of IFRS. The adoption of IFRS 1 will include the restatement of periods beginning January 1, 2010, and the election of various policy options, as allowed. We do not have an estimate of these impacts.

Accounting for the effects of rate regulation

Unlike Canadian GAAP, IFRS does not currently include specific provisions for accounting for the effects of rate regulation. As such, as part of our conversion to IFRS, we are reviewing each of our regulatory assets and liabilities to determine whether they meet the definition and recognition criteria found in the International Accounting Standards Board's Framework for the Preparation and Presentation of Financial Statements and the specific IFRS standards. There is a possibility that any or all of these items may not meet the definition of an asset or liability upon implementation of IFRS. In that case, these assets and liabilities would be written-off at implementation and the future economic effects of these types of items would be recognized in earnings of the period in which they occurred.

Employee future benefit costs

We expect that there will be a charge to retained earnings upon adoption of IFRS as a result of the write-off of accumulated unamortized actuarial losses and transition obligations recorded under Canadian GAAP on the date of transition.

Property, plant and equipment

Property, plant and equipment accounting changes could see the following impacts:

- Certain indirect overhead costs previously capitalized under Canadian GAAP may be required to be written off at implementation. For periods after the implementation of IFRS, those types of indirect overhead costs may also need to be expensed in the period in which they are incurred.

- Adjustments to the opening net book value for items that would not have been capitalized if we had been applying IFRS since our inception.

- Under IFRS, we will record and depreciate property, plant and equipment based on the life of specific components of individual assets.

Impact on Financial Systems

We expect that conversion to IFRS will significantly impact our financial systems, primarily driven by the fact that IFRS does not currently include specific provisions for accounting for the effects of rate regulation. We anticipate that we will need to maintain three sets of records; one that is based on policies in accordance with IFRS, a second that is used for reporting to the OEB for rate-setting purposes, and a third that is based on US GAAP for the preparation of consolidated financial statements by our parent company. Our conversion plan includes an upgrade to our financial system for completion during the second quarter of 2010.

Disclosure controls and procedures and internal control over financial reporting

Accounting policy changes will need to be embedded into our financial data and reporting systems. These impacts are being addressed throughout 2009 during the solution development and implementation stages.

Financial Reporting Expertise

During the design and planning phase, we established a staff communication plan, and are currently executing our staff training programs. Our training program began during 2007 and will continue through 2011. Our training program is targeted at both finance and non-finance groups, including our board of directors, executives, treasury, internal audit, regulatory, business development and external relations personnel.

Business activities

The OEB has begun an IFRS consultation process to determine the nature of any changes that should be considered in regulatory accounting requirements in response to the introduction of IFRS. Along with other industry representatives, we are participating in this process. As IFRS does not currently include specific provisions for accounting for the effects of rate regulation, there could be significant changes in the way we are required to capture and report data should the OEB not adopt IFRS in its entirety.

We are also working with our treasury department to understand the impact that IFRS will have on our ability to comply with our debt covenants.

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas' system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the consolidated financial statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board of Directors, as does the Director of Internal Audit Services.

Deloitte & Touche LLP performed an independent audit of the 2008 and 2007 consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

March 13, 2009

Julie Dill
President

J. Patrick Reddy
Chief Financial Officer

Deloitte

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Auditors' report

To the Shareholders of
Union Gas Limited

We have audited the consolidated balance sheets of Union Gas Limited (the "Company") as at December 31, 2008 and 2007 and the consolidated statements of income and comprehensive income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

March 13, 2009

UNION GAS LIMITED
Consolidated Statements of Income and Comprehensive Income

For the Years Ended December 31 ($millions)	**2008**	2007
Gas sales and distribution revenue	**1,852**	1,811
Cost of gas (note 20)	**1,177**	1,156
Gas distribution margin	**675**	655
Storage and transportation revenue (note 20)	**244**	215
Other revenue	**34**	37
	953	907
Expenses		
Operating and maintenance (note 20)	**336**	327
Depreciation and amortization (note 8)	**186**	174
Property and capital taxes	**65**	66
	587	567
Income before other items	**366**	340
Other income	**3**	5
Income before interest and income taxes	**369**	345
Interest expense (notes 11 and 20)	**148**	152
Income before income taxes	**221**	193
Income taxes (note 19)	**41**	48
Net income and comprehensive income	**180**	145
Preference share dividends	**5**	5
Earnings applicable to common shares	**175**	140

(See accompanying notes)

UNION GAS LIMITED
Consolidated Statements of Retained Earnings

For the Years Ended December 31 ($millions)	**2008**	2007
Retained earnings, beginning of year	**628**	522
Accounting policy change (note 1)	–	2
Revised retained earnings, beginning of year	**628**	524
Net income and comprehensive income	**180**	145
Dividends		
Preference shares	**(5)**	(5)
Common shares	**(115)**	(36)
Retained earnings, end of year	**688**	628

(See accompanying notes)

UNION GAS LIMITED
Consolidated Balance Sheets

As at December 31 ($millions)	**2008**	2007
Assets		
Current assets		
Accounts receivable (notes 5, 6 and 20)	**539**	374
Income taxes receivable	–	1
Inventories (note 7)	**228**	163
Future income taxes (note 19)	**19**	33
Total current assets	**786**	571
Property, plant and equipment, net (note 8)	**3,827**	3,606
Investments and other assets (notes 9 and 18)	**252**	236
Total Assets	**4,865**	4,413
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term borrowings (notes 4 and 20)	**321**	350
Accounts payable and accrued charges (notes 6, 10 and 20)	**560**	528
Income taxes payable (note 19)	**4**	–
Long-term debt and obligation under capital lease due within one year (note 11)	**29**	108
Total current liabilities	**914**	986
Long-term liabilities		
Long-term debt and obligation under capital lease (note 11)	**2,200**	1,732
Mandatorily redeemable preference shares (note 12)	**5**	5
Future income taxes (note 19)	**117**	118
Asset retirement obligations (note 14)	**75**	71
Deferred credits and other liabilities (notes 2 and 18)	**124**	130
Total long-term liabilities	**2,521**	2,056
Total Liabilities	**3,435**	3,042
Contingencies (note 21)		
Non-controlling interest (note 3)	**10**	10
Shareholders' equity		
Share capital (note 13)	**732**	732
Contributed surplus (note 15)	–	1
Retained earnings	**688**	628
Total Shareholders' Equity	**1,420**	1,361
Total Liabilities and Shareholders' Equity	**4,865**	4,413

(See accompanying notes)

Approved by the Board

Director

Director

UNION GAS LIMITED
Consolidated Statements of Cash Flows

For the Years Ended December 31 ($millions)	**2008**	2007
Operating Activities		
Net income	**180**	145
Items not affecting cash		
Depreciation and amortization	**187**	176
Gain on sale of land	–	(5)
Asset removal costs	**(1)**	(5)
Future income taxes	**14**	21
Non-cash changes in working capital		
Accounts receivable	**(133)**	46
Inventories	**(65)**	177
Account payables, accrued charges and other	**(20)**	(256)
	162	299
Investing Activities		
Additions to property, plant and equipment	**(404)**	(373)
Acquisition of subsidiary (note 3)	–	(13)
Proceeds on sale of property, plant and equipment	–	6
	(404)	(380)
Financing Activities		
Increase (decrease) in short-term borrowings	**(29)**	350
Long-term debt issued	**500**	–
Long-term debt retired and obligation under capital lease paid	**(109)**	(337)
Dividends paid	**(120)**	(41)
	242	(28)
Change in cash and cash equivalents, during the year	–	(109)
Cash and cash equivalents, beginning of year	–	109
Cash and cash equivalents, end of year	–	–
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**149**	174
Cash payments of income taxes	**28**	132

(See accompanying notes)

UNION GAS LIMITED
Notes to Consolidated Financial Statements
December 31, 2008 and 2007

Union Gas Limited (Union Gas or the Company) owns and operates natural gas transmission, distribution and storage facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. In total, the Company has approximately 5,000 kilometres of high-pressure transmission pipeline and approximately 60,000 kilometres of distribution main and service pipelines. The Company's underground natural gas storage facilities have a working capacity of more than 155 billion of cubic feet (Bcf) and are the largest in Canada.

1. Significant Accounting Policies

Accounting Principles

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and certain transactions have been recorded using accounting principles for rate-regulated enterprises as discussed below under "Regulation." The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates. Management's significant estimates include unbilled revenue, a provision for doubtful accounts, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Financial Instruments

Recognition, Measurement, Disclosure and Presentation of Financial Instruments

Effective January 1, 2007, the Company adopted the standards of the Canadian Institute of Chartered Accountants (CICA) Handbook Sections related to Financial Instruments. The changes have been made in accordance with the transitional provisions of Section 1530, Comprehensive Income; Section 3855, Financial Instruments – Recognition and Measurement; Section 3861, Financial Instruments – Disclosure and Presentation; Section 3251, Equity and Section 3865, Hedges. These sections apply to fiscal years beginning on or after October 1, 2006.

Section 1530 provides standards for the reporting and presentation of comprehensive income, which represents the change in equity from transactions and other events and circumstances from non-owner sources. Other comprehensive income includes revenues, expenses, gains and losses that are recognized in comprehensive income but excluded from net income, in conformity with GAAP. The Company did not have any other comprehensive income during the period or any prior periods presented.

Under the new standards, all financial assets must be classified as held for trading, held-to-maturity investments, loans and receivables or available-for-sale. All financial liabilities must be classified as held for trading or other financial liabilities. When a financial asset or financial liability is initially recognized, it is recorded on the balance sheet at fair value. After initial recognition, financial instruments are measured at their fair values, except for held-to-maturity investments, loans and receivables and other financial liabilities, that are measured at amortized cost. The effective interest related to the financial liabilities and the gain or loss arising from a change in the fair value of a financial asset or financial liability classified as held for trading is included in net income for the period in which it arises. If a financial asset is classified as available-for-sale, the gain or loss should be recognized in other comprehensive income until the financial asset is derecognized at which time the cumulative gain or loss is recognized in net income.

The Company previously engaged in financial hedging activity for the purpose of managing the risk associated with market fluctuations in the cost of natural gas. However, a July 2008 OEB decision found that there is no material net benefit to Union Gas' customers of financially hedging the Company's natural gas commodity costs, and disallowed the recovery of the costs associated with the risk management program that were previously embedded in distribution rates. In September 2008, the Company exited all remaining financial positions and ceased all financial hedging activity. Previous to the discontinuance of financial hedging, contracts that remained open at the balance sheet date were marked to market with an offsetting amount, representing an unrealized gain/loss, being deferred and reflected in future rates. The discontinuance of Union Gas' commodity risk management program did not have a material impact on the Company's consolidated financial statements.

Short-term borrowings have been classified as held for trading. Accounts receivable have been classified as loans and receivables. Accounts payable and accrued charges, long-term debt and mandatorily redeemable preference shares have been classified as other financial liabilities.

The result of the implementation of these new standards is that long-term debt is now presented at amortized cost rather than carrying value. Prior to this change, the Company used the straight line method to calculate the carrying value of deferred charges including debt issuance discounts and related transaction costs. Transaction costs, defined as incremental costs directly attributable to the acquisition, issue or disposal of a financial asset or liability, adjust the carrying amount of the underlying instrument. The Company has adopted a policy of amortizing these costs over the instrument's remaining expected life using the effective interest rate method and are included in interest expense. The difference between the initial measurement and the carrying value has been adjusted to retained earnings at January 1, 2007. The increase (decrease) on the related financial statement items as of January 1, 2007 is as follows:

($millions)	Financial Statement Classification	January 1, 2007	December 31, 2006	Net Financial Statement Impact
Deferred financing charges	a	–	9	(9)
Long-term debt	b	2,172	2,183	(11)
Shareholder's equity	c	1,257	1,255	2

Financial Statement Classification
(a) Investments and other assets
(b) Long-term debt
(c) Retained earnings

Capital Disclosures

Section 1535 of the CICA Handbook, Capital Disclosures, requires an entity to disclose information to enable users of its financial statements to evaluate the entity's objectives, policies and processes for managing capital. The Company adopted the recommendations of this section effective January 1, 2008. Disclosure requirements pertaining to Section 1535 are contained in note 16.

Inventories

In June 2007, the CICA issued Section 3031, Inventories, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards and provides additional guidance on the measurement and disclosure requirements for inventories. Specifically, Section 3031 requires inventories to be measured at the lower of cost and net realizable value. This standard was adopted by the Company effective January 1, 2008 and did not materially impact the Company's interim consolidated financial statements.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Union Gas and its subsidiary (see note 3).

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act* (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, with the exception of the items noted below, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecast revenues and manage costs.

Rates for fiscal 2005, 2006 and 2007 were approved by the OEB on the basis of previously approved items, fiscal 2007 being the last year of traditional cost of service regulation.

Rates effective January 1, 2007 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2008, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The Company is expected to set rates for 2013 on a cost of service basis.

In November 2006, the Company received a decision from the OEB on the regulation of rates for gas storage services in Ontario. The OEB found that the storage market is competitive. As a result the OEB will not regulate the prices of storage services to ex-franchise customers or the prices of new storage services to in-franchise customers. Existing storage services to in-franchise customers will continue to be provided at cost-based rates. All other services continue to be regulated by the OEB.

The Company follows Canadian GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred, or for certain net revenues beyond a pre-established threshold. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Deferred Charges

Certain costs have been deferred for future recovery from customers based on approved OEB rate orders and mechanisms.

Costs related to the issuance of long-term debt are deferred and amortized over the term of the respective debt issues using the effective interest rate method.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred in either accounts receivable (note 5) or accounts payable and accrued charges (note 10) for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby actual earnings in 2008 above an allowable return on equity were shared equally between ratepayers and the Company. A provision of $17 million was recognized as a reduction of gas sales and distribution revenue and as an obligation in accounts payable and accrued charges for 2008. No such mechanism was in place for 2007.

Natural Gas Risk Management Contracts

The gas supply portfolio of the Company includes both fixed price contracts and contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are primarily indexed to either the New York Mercantile Exchange natural gas futures contracts or the Canadian Gas Price Reporter that publishes Alberta index prices.

The Company previously engaged in financial hedging activity for the purpose of managing the risk associated with market fluctuations in the price of natural gas. However, a July 2008 OEB decision found that there is no material net benefit to the Company's customers of financially hedging Union Gas' natural gas commodity costs, and disallowed the recovery of the costs associated with the risk management program that were previously embedded in distribution rates. In September 2008, the Company exited all remaining financial positions and ceased all financial hedging activity.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments with an original maturity of three months of less. See note 20 for discussion of related party transactions.

Income Taxes

Regulated operations

The Company records income tax expense for its regulated operations using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Generally, rates and revenues for regulated utility operations include the recovery of only such income taxes that are currently payable. Accordingly, with the exceptions that follow, the Company does not provide for future income taxes. The flow through tax accounting methodology is followed for accounting purposes as there is reasonable expectation that all such taxes will be recovered in regulated rates when they become payable.

Certain exceptions to the flow through tax accounting methodology for regulated operations have been approved by the OEB. The Company accounts for future income taxes on temporary differences between the approved cost and the actual cost of gas, on temporary differences arising on certain employee future benefits deferred in the financial statements and on certain regulatory deferral accounts.

Prior to 1997, the Company utilized the tax allocation method to account for income taxes. Under this method, provision was made for income taxes deferred to future years principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the financial statements. The corresponding future tax liability is valued at the income tax rates in effect during the periods in which these timing differences will reverse. In addition to the future tax liability, the Company has recognized a ratepayer liability of $72 million (2007 – $84 million) that has been included in deferred credits and other liabilities. This liability represents the difference between the value of the future tax liability and the accumulated timing differences valued at the income tax rates in effect during the periods in which the timing differences occurred.

As approved by the OEB, the balance in the future tax liability is reduced as the timing differences that gave rise to these future income taxes reverse, resulting in an additional exception to the flow through tax accounting methodology. The timing differences are expected to fully reverse by 2018. The ratepayer liability will be refunded through future rate reductions. This liability is also expected to be fully refunded by 2018.

Unregulated operations

The Company is required to utilize the tax allocation method to account for accumulated timing differences related to assets used in the unregulated operations. The accumulated timing differences arise primarily as a result of claiming capital cost allowance for income tax purposes in excess of, or less than, depreciation provided in the financial statements.

Inventories

Gas in storage for resale to customers is carried at costs approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred in either accounts receivable (note 5) or accounts payable and accrued charges (note 10) for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are carried at cost which includes all direct costs, overhead attributable to construction and interest capitalized during construction. The cost of property, plant and equipment is reduced by contributions and grants in aid of construction received from customers and governmental bodies in support of specific transmission and distribution facilities.

Depreciation is provided on the straight-line method at various rates based on the average service life of each class of property. The range of average service life of each class of property is as follows:

Distribution	21-60 years
Transmission	27-50 years
Storage	23-45 years
General	4-47 years

Depreciation rates are determined by periodic review. The depreciation rates for regulated property, plant and equipment are approved by the OEB.

Disposal of Property, Plant and Equipment – Regulated Operations

The original cost of depreciable units retired, together with the net cost of removal less salvage, is charged to accumulated depreciation. Under this method, no income or loss is recognized on ordinary retirements of depreciable property.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation (ARO), where a legal obligation exists, as a liability in the period in which it is incurred provided a reasonable estimate of fair value can be determined. The associated asset retirement cost is added to the carrying amount of the related asset. The liability is accreted over the estimated life of the related asset.

Stock-Based Compensation

The Company participates in a Spectra Energy stock-based compensation plan, which is described in note 15. The Company accounts for stock-based payments to non-employees and direct awards to employees and non-employees using a fair value-based method of accounting. Share appreciation rights (SARs) and similar awards to be settled in cash or equity are accounted for by measuring the amount by which the quoted market price exceeds the option price at the balance sheet date. The Company uses the fair value-based method to account for all other stock-based transactions with employees.

The Company accounts for stock options by measuring the fair value of the stock options using the Black Scholes option pricing model. Compensation cost is then recognized over the vesting period. The Company accounts for phantom stock and performance shares by measuring the fair value of the instrument at the grant date and recognizing the cost over the vesting period. All expense amounts are recorded as a charge to operating and maintenance expense.

Employee Benefit Plans

The Company uses the projected benefit method prorated on services to account for defined benefit pension and post-retirement benefits other than pensions earned by employees.

The Company accrues obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value. The calculation of the expected return on assets is based on the market-related value of assets.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service life of employees active at the date of amendment.

The amount by which the net unamortized cumulative actuarial gain or loss exceeds ten percent of the greater of the accrued benefit obligation or the market-related value of plan assets at the beginning of the year is amortized over the expected average remaining service period of the active employees.

The average remaining service period of active employees covered by the pension plans and the post-retirement benefits other than pension plans is 10 and 18 years, respectively.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs in the period incurred.

Future Accounting Changes

Rate-regulated operations

Effective January 1, 2009, amendments have been made to certain sections of the CICA Handbook related to rate-regulated accounting.

CICA Section 3465, Income Taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities and a corresponding regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a pre-tax basis in the financial statements. The impact of these changes results in an increase in regulatory assets and an increase in future income tax liabilities of approximately $273 million on January 1, 2009.

CICA Section 1100, Generally Accepted Accounting Principles has been amended to remove a temporary exemption pertaining to the application of the recognition and measurement of assets and liabilities arising from rate regulation. In the absence of specific CICA guidance due to the removal of the temporary exemption related to rate regulated accounting, the CICA has permitted reliance on an other source of GAAP, specifically Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). FAS 143 requires negative salvage, currently included in property, plant and equipment, to be reported as a regulatory liability. The impact of these changes results in an increase in property plant and equipment and an increase in regulatory liabilities of approximately $402 million on January 1, 2009.

Goodwill

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, Union Gas will adopt the new standards for its fiscal year beginning January 1, 2009. The new section establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recording by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The impact of these changes does not have a material impact on the consolidated financial statements of the Company.

2. Financial Statement Effects of Rate Regulation

The following describes each of the circumstances in which rate regulation could affect the accounting for a transaction or event. For certain of these regulatory items, the expected recovery/settlement period, or likelihood of recovery/settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. In the absence of rate regulation, balance sheet items presented below could be higher (lower) by:

($millions)	**Financial Statement Classification**	**Recovery/ Settlement Period**	**2008**	2007
Assets				
Other deferrals	a	A	**(24)**	(15)
Deferred mark-to-market losses	a	A	**–**	(7)
Gas in storage inventory	b	A	**(40)**	(20)
Future income taxes (current)	e	A	**1**	2
Total assets			**(63)**	(40)
Liabilities				
Asset removal costs	c	C	**(402)**	(385)
Other deferrals – current	d	A	**(20)**	(13)
Other deferrals – long-term	f	B	**(72)**	(84)
Gas cost deferrals	d	A	**(19)**	(100)
Storage and transportation deferrals	d	A	**(33)**	(7)
Future income taxes (long-term)	e	C	**195**	175
Total liabilities			**(351)**	(414)

Financial Statement Classification

(a) Accounts receivable
(b) Inventories
(c) Accumulated depreciation
(d) Accounts payable and accrued charges
(e) Future income tax asset/liability
(f) Deferred credits and other liabilities

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 10 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Other deferrals

As prescribed by regulatory order, the Company has various amounts included in customer rates that are intended to recover specifically-identified costs. To the extent that the actual costs differ from forecast costs or revenues, the variance is deferred for future recovery from or refund to ratepayers. In the absence of rate regulation, after-tax earnings for 2008 could have been $9 million lower (2007 - $19 million higher) because GAAP for non-regulated entities would require that all customer rate revenue and costs be recognized in income when earned.

Deferred mark-to-market gains/losses

The Company previously engaged in financial hedging activity for the purpose of managing the risk associated with market fluctuations in the price of natural gas. However, a July 2008 OEB decision found that there is no material net benefit to the Company's customers of financially hedging Union Gas' natural gas commodity costs, and disallowed the recovery of the costs associated with the risk management program that were previously embedded in distribution rates. In September 2008, the Company exited all remaining financial positions and ceased all financial hedging activity. Previous to the discontinuance of financial hedging, contracts that remained open at the balance sheet date were marked to market with an offsetting amount, representing an unrealized gain/loss, being deferred. In the absence of rate regulation, after-tax earnings for 2008 could have been $5 million higher (2007 - $7 million higher), because GAAP for non-regulated entities would require that these unrealized gains/losses be recognized in the current period (see note 17).

Gas in storage

Gas in storage is carried at the weighted average cost of gas as approved by the OEB. In the absence of rate regulation, after-tax earnings for 2008 could have been $13 million lower (2007 - $38 million higher), because GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost and net realizable value.

Future income taxes

The Company accounts for income taxes using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Generally, rates and revenues for utility operations include recovery of only such income taxes as are currently payable. Accordingly, the Company does not provide for income taxes deferred to future years as a result of differences in the treatment for income tax and accounting purposes of various items of income and expenditure. In the absence of rate regulation, after-tax earnings for 2008 could have been $21 million lower (2007 - $7 million higher).

Asset removal costs

The Company has recorded a reduction to property, plant and equipment as a result of estimated removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs may not have been recorded and after-tax earnings for 2008 could have been $12 million higher (2007 - $13 million higher).

Gas cost deferrals

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis, to ensure that customers' rates reflect future expected costs based on published forward market prices. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These deferred amounts are subject to review and approval by the OEB on an annual basis in the normal course. The regulatory asset or liability represents the difference between actual gas commodity costs incurred and the amount included in approved rates. In the absence of rate regulation, after-tax earnings for the 2008 could have been $54 million lower (2007 - $61 million lower) because GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred.

Storage and transportation deferrals

The Company earns revenue for providing storage and transportation services to customers. The forecast of this revenue is one component used to establish Union Gas' rates for services. Storage and transportation deferral accounts accumulate any difference between the actual revenue earned in providing these storage and transportation services and the forecast revenue approved by the OEB for rate-making purposes. In the absence of rate regulation, GAAP for non-regulated entities would require that actual storage and transportation revenue be recognized in income when earned. After-tax earnings for 2008 could have been $17 million higher (2007 - $7 million lower), if these transactions were accounted for under GAAP for non-regulated entities.

Property, plant and equipment

In the absence of rate regulation, property, plant and equipment may not include overhead costs since these costs may have been charged to earnings in the period in which they occurred. As such, annual operating and maintenance costs could have been higher by the amounts capitalized and depreciation could be lower due to the impact of lower capitalized costs. These amounts are not readily determinable.

3. Acquisition of Subsidiary

In December 2007, the Company acquired a 75% ownership interest in Huron Tipperary Limited Partnership I for consideration of $36 million. The Company recorded this acquisition using the purchase method and consolidates its results since the acquisition date.

The allocation of the acquisition price based on the fair values of the assets acquired less the liabilities assumed by the Company is as follows:

($millions)	**2007**
Assets acquired:	
Note receivable	23
Asset under construction	20
	43
Non-controlling interest	(10)
Fair value of net assets acquired	33
Net consideration paid:	
Cash	13
Note payable	23
	36
Goodwill	3

4. Short-Term Borrowings

($millions)	**2008**	2007
Short-term borrowings and bank indebtedness (note 20)	**(115)**	(113)
Commercial paper	**(206)**	(237)
	(321)	(350)

The Company has total bank lines of credit of $525 million (2007 - $525 million). The lines of credit include a committed credit facility of $500 million (2007 - $500 million) with a five-year term that commenced in July 2007 and a $25 million (2007 - $25 million) operating facility. The committed facility includes a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The bank lines of credit are unsecured.

These lines of credit enable Union Gas to borrow directly from banks, issue bankers' acceptances and support a commercial paper program. A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper at rates generally below the prime lending rate. The average interest rate on short-term borrowings for the year ended December 31, 2008 was 3.21% (2007 – 4.80%).

Total short-term interest paid in 2008 was approximately $5 million (2007 – approximately $2 million).

5. Accounts Receivable

($millions)	**2008**	2007
Trade	**429**	318
Gas imbalances (note 6)	**69**	37
Regulatory (note 2)	**22**	9
Other	**19**	10
	539	374

See note 20 for discussion of related party transactions.

6. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the balance sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2008 accounts receivable and accounts payable include approximately $69 million (2007 – $37 million) related to gas imbalances and gas balancing services.

7. Inventories

($millions)	**2008**	2007
Gas in storage	**199**	137
Materials and supplies	**29**	26
	228	163

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are used in the operation and maintenance of the Company's system.

8. Property, Plant and Equipment, net

($millions)	**2008**	2007
Cost		
Distribution	**3,361**	3,223
Transmission	**1,562**	1,453
Storage	**818**	709
General	**277**	277
	6,018	5,662
Accumulated depreciation		
Distribution	**1,294**	1,219
Transmission	**506**	469
Storage	**273**	257
General	**118**	111
	2,191	2,056
Net book value	**3,827**	3,606

Property, plant and equipment are recorded net of contributions in aid of construction made by customers. Depreciation rates used during the year ended December 31, 2008 resulted in an average rate of 3.34% (2007 – 3.31%).

Included in property, plant and equipment are the following:

($millions)	**2008**	2007
Assets not subject to depreciation [13]	**219**	266
Asset retirement costs	**20**	20
Interest charge capitalized during the year	**7**	4
Equipment under capital lease, net of accumulated amortization of $3 (2007 – $3)	**2**	2

[13] Assets not subject to depreciation include land, base pressure gas in storage reservoirs and assets under construction.

9. Investments and Other Assets

($millions)	**2008**	2007
Gas balancing for direct purchase customers [14]	**130**	130
Employee future benefits (note 18)	**110**	93
Goodwill	**12**	12
Other	–	1
	252	236

10. Accounts Payable and Accrued Charges

($millions)	**2008**	2007
Trade	**120**	132
Gas imbalances (note 6)	**69**	37
Regulatory (note 2)	**68**	107
Accrued charges	**303**	252
	560	528

See note 20 for discussion of related party transactions.

[14] Bundled delivery service customers are required to balance their gas supply and gas consumption annually. To provide this service the Company owns gas to meet the customers' demand for gas during the year. This balancing gas is recorded at cost.

11. Long-term Debt and Obligation Under Capital Lease

($millions)		2008	2007
Sinking fund debentures			
11.55%	1988 Series II debentures, due October 15, 2010	**41**	45
10.75%	Senior debentures, due July 31, 2009	**24**	27
Other long-term debt			
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
7.90%	1994 Series II debentures, due February 24, 2014	**150**	150
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
Medium-term note debentures			
5.70%	Series 1, redeemed July 2008	–	100
7.20%	Series 2, due June 1, 2010	**185**	185
6.65%	Series 3, due May 4, 2011	**250**	250
4.64%	Series 5, due June 30, 2016	**200**	200
5.46%	Series 6, due September 11, 2036	**165**	165
5.35%	Series 6, due April 27, 2018	**200**	–
4.85%	Series 7, due April 25, 2022	**125**	125
6.05%	Series 7, due September 2, 2038	**300**	–
		2,240	1,847
Less: deferred financing charges		**12**	10
		2,228	1,837
Obligation under capital lease		**1**	3
		2,229	1,840
Less: current portion		**29**	108
		2,200	1,732

The Company's long-term debt is unsecured. The weighted average cost of long-term debt for the year ended December 31, 2008 was 7.1% (2007 – 7.9%). Principal repayment requirements on long-term debt are as follows:

($millions)	Total	2009	2010	2011	2012	2013	Thereafter
Long-term debt	2,240	28	222	250	–	–	1,740
Capital lease obligation	1	1	–	–	–	–	–
Total	2,241	29	222	250	–	–	1,740

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2008 and 2007, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2008 was $143 million (2007 - $167 million).

Total interest paid on the obligation under capital lease was less than $1 million in 2008 and in 2007.

12. Mandatorily Redeemable Preference Shares

Authorized		Outstanding 2008	2007	2008	2007
(shares)		*(shares)*		*($millions)*	
Class A – 112,072	Series A, 5.5%	**47,672**	47,672	**3**	3
	Series C, 5.0%	**49,500**	49,500	**2**	2
				5	5

The Class A Preference Shares, Series A and C are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

13. Share Capital

	Authorized	Outstanding 2008	2007	2008	2007
	(shares)	*(shares)*		*($millions)*	
Class A, Series B, 6%	90,000	90,000	90,000	**5**	5
Class B, Series 11, 4.79%	Unlimited	4,000,000	4,000,000	**100**	100
				105	105
Common Shares	Unlimited	57,822,650	57,822,650	**627**	627
				732	732

The Class A, Series B Preference Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 11 Preference Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 10 shares every five years commencing January 1, 2009.

On January 1, 2009, all of the holders of the Cumulative Redeemable Convertible Class B Preference Shares, Series 11 (Series 11 Shares) exercised their option to convert their shares back into 4.88% Cumulative Redeemable Convertible Class B Preference Shares, Series 10 (Series 10 Shares). Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. On January 1, 2014, holders of Series 10 Shares have the right at their option, to convert all or any of the Series 10 Shares into Series 11 Shares. The dividend rate on the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

In February 2009, all of the common shares of Union Gas were transferred to Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast).

14. Asset Retirement Obligation

The Company has a legal obligation to disconnect, purge and cap any abandoned pipeline. The Company also has buildings that contain asbestos and therefore has a legal obligation requiring the special handling and disposition of the asbestos if it is disturbed. An ARO has been recorded for both of these items.

The Company also has unrecorded AROs for its storage wells, easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to these ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of Union Gas' business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate the fair value of the AROs.

At December 31, 2008, the estimated undiscounted cash flows required to settle the AROs of the Company was $468 million (2007 – $468 million), calculated using an inflation rate of 2.0% per annum. The estimated fair value of this liability was $75 million (2007 – $71 million) after discounting the estimated cash flows at a rate of 5.5% per annum. At December 31, 2008, the timing of payment for settlement of the obligations ranges from 9 to 47 years.

Reconciliation of Asset Retirement Obligations:

($millions)	**2008**	2007
Balance, beginning of year	**71**	67
Accretion expense	**4**	4
Balance, end of year	**75**	71

15. Stock-Based Compensation

Under the Long-Term Incentive Share Option Plan 1989 (1989 Plan), the Company's parent company, Westcoast, has granted certain stock options to its employees, including employees of the Company. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of Westcoast's shares on the date of grant.

Regular stock options vest in five equal stages with the first stage vesting immediately on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of grant. Key employee retention stock options commence vesting two years after the date of issuance and then vest in three equal annual instalments. The maximum term of both stock options awarded under the 1989 Plan is ten years. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

Performance-based stock options commence vesting when a pre-determined performance threshold has been achieved. The options then vest in three equal annual stages commencing on the date the performance threshold is achieved. The maximum term for performance-based options awarded under the 1989 Plan ranges from five to eight years. Share appreciation rights have not been attached to performance-based options awarded under the 1989 Plan.

Under the terms of the acquisition of Westcoast by Duke Energy, all of the issued and outstanding stock options of Westcoast were exchanged for replacement options to purchase Duke Energy common shares at an exchange ratio specified in the purchase agreement. All terms and conditions of the replacement options were substantially the same as the terms and conditions of the options of Westcoast.

Duke Energy's 1998 Long-Term Incentive Plan (1998 Plan), as amended, reserved 60 million shares of common stock for awards to employees and outside directors. Under the 1998 Plan, the exercise price of each option granted cannot be less than the market price of Duke Energy's common stock on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to five years. There were no stock options granted under the 1998 Plan in 2008 or 2007.

At the time Spectra Energy was spun-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) on Duke Energy common stock held by Duke Energy and Spectra Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. In the case of stock options, in accordance with the separation agreements, the option price conversion was based on the pre-distribution Duke Energy closing price of $19.14 relative to the Spectra Energy when-issued closing price of $28.62 on January 3, 2007. The revised awards therefore maintained both the pre-conversion aggregate intrinsic value of each award and the ratio of the exercise price per share to the fair market value per share. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy stock options, restricted stock awards, performance awards and phantom stock awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

The conversion of Duke Energy stock awards to Spectra Energy stock awards constituted a modification of those stock awards under the provisions of SFAS No. 123(R). However, under the provisions of FASB Staff Position (FSP) No. 123(R)-5, since the modification was made to stock awards issued to employees for instruments that were originally issued as compensation and then modified, and that modification was made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments occurred as (a) there was no increase in fair value of the awards (the holders were made whole) and (b) all holders of the same class of equity instruments (for example, stock options) were treated in the same manner.

In connection with the spin-off, on December 19, 2006, Spectra Energy adopted, and Duke Energy as its sole stockholder prior to the spin-off approved, the Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP). The 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. Terms and key provisions of the 2007 LTIP are substantially similar to the terms of the Duke Energy 2006 Long-term Incentive Plan. A maximum of 30 million shares of common stock may be awarded under the 2007 LTIP.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have 10-year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. For the year ended December 31, 2007, Spectra Energy granted to Union Gas employees 188,100 options at a price of $6.71 per share (total fair value of US$1 million) no options were granted in 2008, and less than US$1 million of compensation expense was attributable to this grant in both 2007 and 2008.

The estimated fair value of these stock options was determined using the Black Scholes option pricing model using the following assumptions.

	2007
Risk free interest rate	4.44%
Expected life (years)	7
Expected volatility	29.50%
Expected dividends	3.4%

A summary of the status of stock options held by employees of Union Gas as at December 31, 2008 and 2007, and changes during the years ended on those dates is presented below:

Spectra Stock Options

	2008		**2007**	
	Shares	**Weighted-Average Exercise Price US$**	Shares	Weighted-Average Exercise Price US$
Outstanding at beginning of year	331,332	$24.75	149,761	$25.53
Transfers out	(25,600)	25.48	-	
Granted	-		188,100	25.64
Exercised	(5,858)	17.49	(1,529)	12.36
Forfeited	(22,725)	25.77	(5,000)	25.64
Outstanding at end of year	277,149	$24.75	331,332	$24.75
Options exercisable at year-end	173,097	$24.21	148,232	$23.64

Exercise Prices US$	Options Outstanding: Number Outstanding At 12/31/08	Options Outstanding: Weighted-Average Remaining Contractual Life	Options Outstanding: Weighted-Average Exercise Price US$	Options Exercisable: Number Exercisable At 12/31/08	Options Exercisable: Weighted-Average Exercise Price US$
$11 - 15	24,700	4.2	$11.86	24,700	$11.86
$16 - 20	18,381	1.0	17.90	18,381	17.90
$21 - 25	186,814	7.2	25.35	82,762	24.98
$26 - 30	20,754	3.1	28.81	20,754	28.81
$31 - 35	16,800	3.0	32.51	16,800	32.51
> $35	9,700	2.0	36.86	9,700	36.86
Total	277,149	5.8	$24.75	173,097	$24.21

Duke Stock Options

	2008 Shares	2008 Weighted-Average Exercise Price US$	2007 Shares	2007 Weighted-Average Exercise Price US$
Outstanding at beginning of year	284,246	$15.82	287,230	$15.74
Transfers in/(out)	(16,900)	22.39	-	-
Exercised	(32,469)	11.16	(2,984)	7.85
Forfeited	(17,886)	17.47	-	-
Outstanding at end of year	216,991	$15.87	284,246	$15.82
Options exercisable at year-end	216,991	$15.87	284,246	$15.82

Exercise Prices US$	Options Outstanding: Number Outstanding At 12/31/08	Options Outstanding: Weighted-Average Remaining Contractual Life	Options Outstanding: Weighted-Average Exercise Price US$	Options Exercisable: Number Exercisable At 12/31/08	Options Exercisable: Weighted-Average Exercise Price US$
$7 - 11	68,954	-	$9.24	68,954	$9.24
$12 - 15	42,123	1.0	14.89	42,123	14.89
$16 - 20	52,914	1.6	18.60	52,914	18.60
$21 - 25	53,000	3.5	22.57	53,000	22.57
Total	216,991	1.4	$15.87	216,991	$15.87

At December 31, 2008 277,149 Spectra Energy common shares were under options at prices ranging from US$11.86 to US$36.86 per share and 216,991 Duke Energy common shares were under option at prices ranging from US$7.85 to US$24.39, of which 51,263 Spectra shares and 95,091 Duke shares are eligible for share appreciation rights that allow the holder to receive 50% of the appreciated value in cash and the balance in common shares of Duke Energy.

The 1998 Plan allows for a maximum of twelve million shares of common stock to be issued under restricted stock awards, stock-based performance awards and phantom stock awards. Stock-based performance awards granted under the 1998 Plan generally vest over three year periods. Vesting can occur in three years if performance is met. Performance awards granted in 2006 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards with the adoption of CICA Handbook Section 3870, Stock-based Compensation. The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant is incorporated within the model. Other awards not containing market conditions are measured at grant date price. There were 48,242 Spectra Energy shares and 70,026 Duke Energy shares outstanding immediately after the spin-off (weighted fair value of approximately US$ 1.3 million). As of December 31, 2008 there were 60,257 Spectra shares and 32,007 Duke shares outstanding (weighted fair value of approximately US$ 2.3 million).

In addition to the spin-off performance awards Spectra awarded 51,500 performance awards (fair value of US$ 1.6 million, market prices of (US$ 30.68, $27.72, $36.28, and $29.06) during 2008. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return (TSR) of Spectra Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using the Monte Carlo valuation method.

Weighted -Average Assumptions for Performance Awards

	2008
Risk free rate of return	1.94 – 2.32%
Expected life (years)	3
Expected volatility Spectra Energy	24.3 – 24.6%
Expected volatility Peer Group	14.2 – 28.9%
Market index	14.3 – 14.7%
Expected dividend yield	–

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

Compensation expense for the performance awards is charged to earnings over the vesting period, and totalled approximately US$ 1 million in 2008 and less than US$1 million for the Company in 2007.

Phantom stock awards granted under the 1998 Plan generally vest over five year periods. There were 36,389 Spectra Energy shares and 45,224 Duke Energy shares outstanding immediately after the spin-off (weighted fair value of approximately US$ 1 million). Spectra Energy granted 47,600 shares (fair value of approximately US$ 1 million at grant dates) to employees of Union Gas in 2008 and 32,700 shares (fair value of approximately US$ 1 million at grant dates) to employees of Union Gas in 2007. As of December 31, 2008 there were 77,909 Spectra shares and 21,368 Duke shares outstanding (weighted fair value of approximately US$ 2.3 million). Compensation expense for the phantom awards is charged to earnings over the vesting period, and totalled approximately US$ 1 million in 2008 and less than US$ 1 million in 2007.

16. Capital Management

The Company's objectives in managing its capital include the continuation of its ability to serve customers and to generate the OEB allowed rate of return for its shareholders while maintaining the OEB-approved level of common equity.

In managing capital, management considers both debt and equity. The mix of debt and equity components is driven by prevailing market conditions, as the Company may take advantage of lower interest rates by issuing debt or utilizing available credit facilities. The Company is required by Undertakings to the Lieutenant Governor in Council (LGIC) of Ontario to maintain sufficient common equity at the level approved by the OEB. The quarterly dividend payment is determined to allow the Company to maintain the common equity component at the level approved by the OEB.

Various debt covenants require the Company to maintain Indebtedness[15] equal to a maximum of 75% of Total Capitalization[16].

As at December 31, 2008 and 2007, the Company was in compliance with the following externally imposed capital requirements. The Company monitors these requirements on a quarterly basis.

	2008	2007
OEB-approved minimum Common Equity	**36.00%**	36.00%
Allowed Return on Equity – regulated operations	**8.54%**	8.54%
Maximum Total Indebtedness to Total Capitalization	**75.00%**	75.00%
Actual Total Indebtedness to Total Capitalization	**64.50%**	62.00%

[15] Indebtedness includes short-term borrowings, long-term debt, letters of credit and guarantees.
[16] Capitalization includes shareholders-equity plus indebtedness.

17. Financial Instruments

Under Canadian GAAP, financial instruments are classified into one of the following five categories: held-for trading, held to maturity investments, loans and receivables, available-for-sale financial assets and other financial liabilities. The carrying value of our financial instruments are classified into the following categories:

Classification

($millions)	**2008**	2007
Loans and receivables[17]	**534**	387
Financial liabilities held for trading[18]	**322**	350
Other financial liabilities[19]	**2,846**	2,398

The Company has determined the estimated fair values of its financial instruments based on appropriate valuation methodologies; however, considerable judgment is required to develop these estimates. The fair values of the Company's financial instruments are not materially different from their carrying value, with the exception of the Company's long-term debt of $2,240 million (2007 - $1,847 million). Based on current interest rates for debt with similar terms and maturities, the fair market value is estimated to be $2,290 million (2007 - $2,109 million).

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2008 is $69 million receivable (2007 - $37 million). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on accounts receivable, the Company performs ongoing credit review of all significant contract customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by Union Gas at December 31, 2008 amounted to $64 million (2007 - $59 million). The Company also held other forms of credit enhancement at December 31, 2008 in the form of letters of credit of $60 million (2007 - $47 million) and parental guarantees of $503 million (2007 - $312 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

[17] Includes accounts receivable
[18] Includes short-term borrowings
[19] Includes accounts payable and accrued charges, long-term debt, and mandatorily redeemable preference shares

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the potential loss is recognized in the income statement within operating and maintenance expenses. When a receivable balance is considered uncollectible, it is written off against the allowance for doubtful accounts. Subsequent recoveries of amounts previously written off are credited against operating and maintenance expenses.

Recently, there have been significant equity and commodity market declines driven by general economic factors and credit concerns, primarily in the financial services sector. The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as a summary of impaired amounts and their related allowance for the doubtful accounts:

($millions)	**2008**	2007
Current	**412**	301
30 Days over due	**12**	11
60 Days over due	**3**	3
90+ Days over due	**9**	8
Total trade accounts receivable	**436**	323
Allowance for doubtful accounts	**(7)**	(5)
Total trade accounts receivable, net	**429**	318
Reconciliation of allowance for doubtful accounts:		
Opening balance	**(5)**	(6)
Increase to allowance	**(9)**	(7)
Write-offs	**7**	8
Ending balance	**(7)**	(5)

For the years ended December 31, 2008 and 2007, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has a $500 million committed credit facility available to help meet short-term financing needs. As of December 31, 2008, $294 million (2007 – $263 million) was available. The Company also has a $25 million operating facility available. As of December 31, 2008, $23 million (2007 – $16 million) was available.

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2008:

($millions)	Total	Less than 1 year	2 – 3 years	4 – 5 years	More than 5 years
Short-term borrowings	321	321	—	—	—
Accounts payable and accrued charges	560	560	—	—	—
Long-term debt	4,050	188	768	245	2,849
Mandatorily redeemable preference shares	5	—	—	—	5
Total	4,936	1,069	768	245	2,854

18. Employee Future Benefits

The Company sponsors five defined benefit registered pension plans and one registered pension plan with both a defined benefit provision and a defined contribution provision. Eligible employees of the Company participate in one of these registered pension plans. All of the defined benefit plans provide a final average earnings related benefit. The Company makes contributions to the defined contribution plan based on the salary, age and service of each member. Supplemental defined benefit pensions are provided to all employees affected by the maximum pension limits under the Income Tax Act. Other post-retirement benefits provided include health and dental benefits, life insurance coverage and a health care spending account.

Accrued benefit obligations are determined using the projected benefit method pro-rated on services. The Company uses a measurement date of September 30. In determining the accrued benefit obligations and current service costs, the Company uses Management's best-estimate assumptions, except for the liability discount rate, which is determined as the yield on high quality fixed income investments with a term to maturity similar to the covered benefits.

Plan assets are valued at fair value. The calculation of the expected return on assets is based on a market related value of assets, with the market related adjustment determined over a three-year period.

The transitional obligation at January 1, 2000 is being amortized on a straight line basis over the expected average remaining service lifetime (EARSL) of employees active at January 1, 2000. Past service costs arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of the amendment. The amount by which the net unamortized cumulative actuarial gain or loss based on the market related value of assets exceeds 10% of the greater of the accrued benefit obligation and the market related value of assets at the beginning of the period is amortized on a straight-line basis over the EARSL of employees active at the beginning of the period. The average remaining service period of the active employees covered by the retirement plans is 10 years. The average remaining service period of the active employees eligible for post retirement benefits other than pensions is 18 years.

In 2008, the Company made the following employee future benefit contributions:

($millions)	**2008**	2007
Defined benefit plans	**28**	27
DC pension plan	**3**	3
Supplemental pension	**1**	1
Other than pensions	**3**	3
	35	34

Benefit Obligations, Plan Assets and Funded Status

	Years Ended December 31,			
	Pension		Other	
($millions)	**2008**	2007	**2008**	2007
Change in benefit obligations				
Balance, beginning of year	**544**	552	**49**	49
Employer current service cost	**10**	11	**1**	1
Member contributions	**3**	2	**–**	–
Interest cost	**30**	28	**3**	3
Benefits paid	**(27)**	(27)	**(3)**	(3)
Actuarial gain	**(31)**	(22)	**(1)**	(1)
Balance, end of year	**529**	544	**49**	49
Change in fair value of assets				
Fair value, beginning of year	**480**	443	**–**	–
Actual return on plan assets	**(60)**	29	**–**	–
Employer contributions	**22**	33	**3**	3
Member contributions	**3**	2	**–**	–
Benefits paid	**(27)**	(27)	**(3)**	(3)
Fair value, end of year	**418**	480	**–**	–
Funded status				
Net funded status	**(111)**	(64)	**(49)**	(49)
Unamortized net actuarial loss	**177**	120	**1**	2
Unamortized past service costs	**8**	9	**–**	–
Unamortized transitional obligation	**9**	11	**11**	13
Contributions remitted after measurement date	**12**	5	**1**	1
Accrued benefit asset (liability), end of year	**95**	81	**(36)**	(33)
Classification of accrued benefit assets (liabilities)				
Deferred charges and other assets	**110**	93	**–**	–
Deferred credits and other liabilities	**(15)**	(12)	**(36)**	(33)
Accrued benefit asset (liability)	**95**	81	**(36)**	(33)
Allocation of assets to major classes				
Equity securities	**57%**	64%	**–**	–
Debt securities	**43%**	36%	**–**	–

For 2008 all of the defined benefit pension plans had accrued benefit obligations that exceeded the fair value of plan assets. For 2007, all but one of the defined benefit pension plans had accrued benefit obligations that exceed the fair value of plan assets. The other post-retirement benefit plans are not pre-funded.

At December 31, 2008 the fair value of the plan assets was $386, a return on assets of (8.7) % since the September 30th measurement date.

	Years Ended December 31,			
	Pension		Other	
($millions)	**2008**	2007	**2008**	2007
Net benefit cost				
Current service cost	**10**	11	**1**	1
Interest cost	**30**	28	**3**	3
Actual return on plan assets	**60**	(29)	**–**	–
Actuarial gains	**(31)**	(22)	**(1)**	(1)
Amortization of transitional obligation	**2**	2	**2**	1
Past service cost	**1**	–	**–**	–
Difference between actual and expected return	**(95)**	(3)	**–**	–
Difference between actual and recognized actuarial gains in year	**38**	33	**1**	1
Difference between actual and recognized past service costs in year	**–**	1	**–**	–
Annual benefit plan cost	**15**	21	**6**	5
Defined contribution cost	**3**	3	**–**	–
Total net benefit cost	**18**	24	**6**	5
Weighted average assumptions used to determine benefit liability				
Discount rate at measurement date	**5.98%**	5.50%	**6.03%**	5.50%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	1.00%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2015**	2011
Weighted average assumptions used to determine net benefit cost				
Discount rate	**5.50%**	5.00%	**5.50%**	5.00%
Expected rate of return on plan assets	**7.25%**	7.25%	**–**	–
Rate of compensation increases	**3.50%**	3.50%	**3.50%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**1.00%**	1.00%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2011**	2010

Sensitivity of key assumptions ($millions)

	Post-Retirement Benefits Other than Pensions	
Assumed change in:	**1% Increase**	**1% Decrease**
Health care cost trend rate		
Change in obligation	**5**	(4)

19. Income Taxes

The provision for income taxes consists of the following:

($millions)	**2008**	2007
Current	**37**	25
Future	**4**	23
	41	48

The year-over-year change in the components of current and future income taxes is primarily due to the difference in the treatment of the approved cost and the actual cost of gas for income tax and accounting purposes.

Net income taxes paid in 2008 were $28 million (2007 - $132 million).

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

($millions)	**2008**	2007
Income before income taxes	**221**	193
Statutory income tax rate (percent)	**33.5**	36.1
Statutory income tax rate applied to accounting income	**74**	70
Decrease resulting from:		
Deductions claimed for income tax purposes in excess of amounts recorded for accounting purposes	**(16)**	(6)
Amortization of future income taxes	**(16)**	(16)
Other	**(1)**	–
Provision for income taxes	**41**	48
Effective rate of income tax (percent)	**18.9**	24.9

The future income taxes recorded in current assets of $19 million (2007 – $33 million) arise from temporary differences primarily related to regulatory deferral accounts.

The long-term future tax liability of $117 million at December 31, 2008 (2007 - $118 million) includes the following:

($millions)	**2008**	2007
Temporary differences related to regulatory deferral accounts	**(3)**	(8)
Temporary differences related to unregulated storage assets	**27**	17
Difference due to tax allocation methodology related to utility operations prior to 1997	**93**	109
	117	118

After 1996, the OEB required the use of the flow through method of accounting for taxes. As approved by the OEB, this balance of $93 million (2007 – $109 million) is reduced as the timing differences that gave rise to these future income taxes reverse. These timing differences are expected to fully reverse by 2018.

Differences between the flow through method, used by the Company, and the liability method are as follows:

	Liability Method		Flow Through Method	
($millions)	**2008**	2007	**2008**	2007
Current future income tax asset	**23**	35	**19**	33
Regulatory asset	**201**	160	**–**	–
Long-term future income tax liability	**394**	364	**117**	118
Regulatory liability	**–**	–	**72**	84
Future income tax expense	**–**	10	**4**	23

20. Related Party Transactions

The Company purchases gas and transportation services at prevailing market prices and under normal trade terms from commonly controlled companies. During the year ended December 31, 2008, these purchases totalled $1 million (2007 - $1 million). The Company may also provide storage and transportation services to commonly controlled companies under normal trade terms. Storage and transportation services provided to commonly controlled Spectra Energy companies totalled less than $1 million during 2008 (2007 – less than $1 million).

The Company provided administrative, management and other services to commonly controlled companies totalling $8 million (2007 - $7 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $6 million (2007 - $6 million).

At December 31, 2008 the Company had intercompany receivable balances of $2 million (2007 - $3 million) and intercompany payable balances of $6 million (2007 - $1 million), which are recorded in accounts receivable and accounts payable, respectively.

During 2008, the Company obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2008 was a $115 million payable (2007 – $104 million payable). These loans are classified as short-term borrowings in 2008. Interest received on these loans during 2008 totalled less than $1 million (2007 – no interest received) and interest paid on these loans totalled $2 million in 2008 (2007 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

21. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its consolidated financial statements.

Class Action Lawsuit

In 2004, the Company was served with two class action claims, seeking relief similar to a case filed against Enbridge Gas Distribution (Enbridge). In 1994, Enbridge, a gas distribution company located in Toronto, Ontario was served with a class action claim seeking, among other things, a declaration that the OEB-approved 5% late payment fee paid by Enbridge's customers since 1981 is interest that exceeds the amount permitted by the Criminal Code of Canada, and that by collecting the late payment fee, Enbridge had been unjustly enriched and those who paid the fee should be entitled to restitution. In December 2006 the court approved settlement of the claim commenced against Enbridge for $22 million, including $11 million in legal fees and expenses, $2 million to be paid to the Class Proceedings Fund (operated by the Law Foundation of Ontario) and a $9 million donation to the Winter Warmth Fund. In February 2008, Enbridge received OEB approval to recover the full cost of the settlement plus interest and the related legal costs from ratepayers over a five year period. In May 2008, the representative plaintiff in the Enbridge claim filed a petition requesting a review of the OEB rate recovery decision. In December 2008, the Lieutenant Governor in Council denied the request and the decision of the OEB was confirmed.

By the date that Union Gas was served with the two class action claims, the structure of the OEB-approved late payment fees charged by the Company had changed from the 5% structure which was the subject of the two Supreme Court of Canada decisions. The Company has calculated the total amount of 5% late payment fees collected since 1994 to be up to $77 million.

In February 2009, the court dismissed one of the class action claims commenced against the Company, and approved settlement of the other class action claim. The amount of the settlement is a total of approximately $9 million, including approximately $3 million in legal fees, disbursements and other expenses, less than $1 million that will be paid to the Class Proceedings fund (operated by the Law Foundation of Ontario) and approximately $5 million to be paid in three equal, annual instalments to the Winter Warmth Fund as administered by the United Way. The Company will be seeking OEB approval in the future to recover the full cost of the settlement plus interest and the related legal costs from ratepayers, however, we cannot provide assurance that we will be successful in the recovery.

22. Comparative Figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

DIRECTORS

David G. Unruh
Corporate Director

Julie A. Dill Chair and President

Bruce E. Pydee
Director

OFFICERS

Julie A. Dill
President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Finance and Regulatory Affairs

Bruce E. Pydee
Vice President and General Counsel

Bohdan I. Bodnar
Vice President, Human Resources

Menelaos Ydreos
Vice President, Marketing and Customer Care

Stephen W. Baker
Vice President, Business Development – Storage and Transmission

Michael P. Shannon
Vice President, Engineering, Construction and Storage and Transmission Operations

Paul Rietdyk
Vice President, Distribution Operations

Allen C. Capps
Vice President and Treasurer

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar
CIBC Mellon

Union Gas Limited preference shares are listed on the Toronto Stock Exchange
Class A - 5½% (UNG.PR.C)

Class A – 6% (UNG.PR.D)

REGISTERED OFFICE
50 Keil Drive North
Chatham, Ontario
N7M 5M1

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31, 2008

Line No.	Particulars ($millions)	Exhibit A Appendix B Schedule 1 Column a	Annual Report	Difference	Notes
		(a)	(b)	(c)	
	Operating Revenue:				
1	Operating revenue	1,869	1,852	(17)	(i)
2	Storage and transportation	243	244	1	(iii)
3	Other	34	34	0	
4		2,146	2,130	(16)	
	Operating Expenses:				
5	Cost of gas	1,171	1,177	6	(ii)
6	Operating and maintenace expenses	335	336	1	(iii)
7	Depreciation	185	186	1	(iii)
8	Other financing	0	0	0	
9	Property and capital taxes	66	65	(1)	(iv)
10		1,758	1,764	6	
11	Earnings Before Interest and Taxes	389	366	(23)	

Notes:

(i) Estimated Earnings sharing provision.

(ii) Provision for regulatory risk.

(iii) Huron Tipperary (unregulated) results included in external financial statements but excluded in Exhibit A.

(iv) Rounding in the external financial statements.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 5, 18, 24

Question:

Union stated that the increased in-franchise distribution revenue experienced in 2008 arose from unusual circumstances that are not expected to continue in 2009 and 2010. $2.6 million is from increased discretionary gas fired power generation at OPG Lennox due to favourable weather in 2008; unplanned coal and nuclear power generation outages; restricted electricity transmission access to Eastern Ontario electricity markets; and favourable natural gas versus residual oil prices.

a) What approximate portion of the $2.6 million was due to favourable weather? Was the impact realized in the winter or summer months?

b) How certain is Union that the additional electric transmission interconnection tie with Quebec will be in place starting in 2009.

c) Please provide the third party forecasts Union used to conclude that that the favourable difference between natural gas and residual oil prices will not continue in 2009 and 2010.

Response:

a) It is not possible to determine what portion of the $2.6 million was due to favourable weather. It was realized in both summer and winter months.

b) Publicly available statements by the IESO indicate that 1250 MW will be tied into the Hawthorne station in Ontario with the Outaouais station in Quebec by mid 2009.

c) The table below presents the energy price forecast which indicates that natural gas is not price competitive with fuel oil in both 2009 and 2010. The comparison is the HFO No. 6 1% Sulphur price with the Natural gas at Dawn, Ontario price.

   The top portion of the table below shows the third party benchmark energy price forecasts for West Texas Intermediate crude oil and the Henry Hub gas price in the spot market.

In the bottom portion of the table, the average estimate for the three source forecasts is indicated for both crude oil and natural gas. The bottom portion of the table also shows the equivalent heavy fuel oil price and the gas price at Dawn Ontario derived from the average price estimates.

Energy Price Forecasts				
	Forecaster	**Issued**	**2009**	**2010**
Crude Oil WTI US$ per barrel	Global Insight	Dec-08	$ 43.08	$ 56.75
	Consensus Economics - Likely	Jan-09	$ 50.51	$ 63.49
	US DOE	Jan 13 2009	$ 43.25	$ 54.50
Natural Gas Henry Hub US$ per mmbtu	Global Insight	Dec-08	$ 5.83	$ 7.06
	Consensus Economics - Likely	Jan-09	$ 5.73	$ 6.86
	US DOE	Jan 13 2009	$ 5.78	$ 6.63
Average of 3 Price Forecast presented Above				
Crude Oil WTI US$ per barrel	*average of 3 price forecasts*		$ 45.61	$ 58.25
HFO No.6 1% S New York US$ per mmbtu	*WTI to HFO price conversion as per Global Insight*		$ 4.76	$ 6.84
Natural Gas Henry Hub US$ per mmbtu	*average of 3 price forecasts*		$ 5.78	$ 6.85
Natural Gas Dawn, Ont. US$ per mmbtu	*$0.25 Henry Hub to Dawn basis price assumed*		$ 6.03	$ 7.10

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 22 - 23

Question:

Union forecasted a $2 million reduction in 2009 general service delivery revenue as a result of significantly lower forecasted growth in the number of billed customers in 2009. Customer additions in 2008 were 20,069. Union forecasted 3,232 customer additions in 2009. Union stated that the low forecast of customer additions in 2009 is based on the expectation that Ontario housing starts will decline by 33% in 2009 (based on a Consensus Economics Report). In addition, customer attrition will rise due to commercial bankruptcies, plant closures and customer credit related issues. Union forecasted 11,153 customer additions in 2010. Union stated that the relatively low forecast of customer additions in 2010 is based on the lingering impact of the current economic recession.

a) Please provide the cited Consensus Economics Report.

b) What is Union's most currently available customer count? Please include the following components: December 2008 count plus 2009 YTD customer additions less 2009 YTD customer attritions.

Response:

a) The column titled Canada in the table below shows the estimates for total Canadian housing starts for the year 2009 issued by Consensus Forecasts over the period January 2008 to May 2009.

   The Consensus Forecast is published monthly by Consensus Economics Inc. of London, England. The consensus for Canada is provided by 15 respondents which include the major chartered banks, brokerage houses, consulting agencies and the University of Toronto. The monthly Consensus Forecast report is a major reference document that Union Gas relies upon to prepare customer forecasts. Under the service agreement between Consensus Economics and Union Gas the monthly publications cannot be reproduced (complete or partial) without prior written permission of Consensus Economics Inc.

By year end 2008, the global recession was plainly evident. Union Gas noted that the Consensus Forecast estimates over the past year and the early months of the current year indicated a continued weakening in the total housing start estimates for 2009 for Canada. The most likely and the low estimates reported in the consensus indicated a significant decline in new housing construction for 2009.

Union Gas prepared an internal analysis of the impact of economic recessions on housing starts to project the path of the consensus estimate. New housing starts represent the majority of new customer attachments. This internal analysis indicated that total housing starts in Canada and Ontario could decline to the 140,000 and 50,000 unit level respectively. Ontario saw 75,076 new housing starts in 2008; the 50,000 estimate for 2009 is a decline of 33 percent.

By the time the evidence was filed in early April 2009, the most likely estimate for housing starts in Canada was 144,000 units; the low estimate was 125,000 units. The current May 2009 Consensus Forecasts housing start estimate is 138,000 units. This now validates the 50,000 housing start estimate for Ontario that was prepared internally.

The recession impact presented in Exhibit A, Appendix C, Schedule 1 shows a decline in customer growth from the budgeted estimates of 14,850. Of these, new residential customers number 7,500 and this estimate was obtained from the housing start analysis. With lower new home additions, approximately 750 fewer commercial & industrial new customers result. This follows past residential – non residential growth trends. The estimate of customer conversion of existing homes was reduced by 2,000 units for the year 2009 given the poor economic outlook. The remaining 4,600 customer reduction represents a loss of customers due to increased commercial bankruptcies, industrial plant closures and credit / non payment related reasons.

As noted in the following table, the Ontario and Union franchise housing start estimates are derived from the Canadian estimates based on the 2008 percent shares.

Total Housing Start Estimates for the Year 2009
in thousands

Issued in the month of	Canada	Ontario	Union Gas Franchise
	(1)	(2)	(3)
Jan-08	195	69	18
Feb-08	196	70	18
Mar-08	196	70	18
Apr-08	196	70	18
May-08	196	70	18
Jun-08	196	70	18
Jul-08	194	69	18
Aug-08	194	69	18
Sep-08	190	68	18
Oct-08	187	67	18
Nov-08	183	65	17
Dec-08	177	63	17
Jan-09	166	59	16
Feb-09	164	58	15
Mar-09	154	55	14
Apr-09	144	51	14
May-09	138	49	13

notes
(1) From monthly Consensus Forecasts issued by Consensus Economics Inc.
(2) Estimated: Ontario in 2008 was 35.6% of Canadian total housing starts
(3) Estimated: Union Gas in 2008 was 26.4% of Ontario total housing starts

b) The table below provides the most current customer count information.

Time Period	No. of Billed Customers	No. of Attachments
December 2008	1,308,905	24,122
April 2009	1,313,231	4,832

The increase in total billed customers is 4,326 of which 3,833 are residential.

The year to date total number of customer attachments numbered 4,832 as compared to 5,902 for the same period in 2008. This represents an 18% drop in activity.

Customer attachments lag building permits by about 5 months. Customer attachments that occurred over the recent January through April period applied for building permits over the August through December 2008 period. The year to date March 2009 building permit data for residential new home construction located in Union's franchise area is indicating a 60 percent decline in annual activity. Union expects customer attachments to decline notably this summer from that observed a year ago and remain depressed over the fall season.

Union Gas stands by its total billed customer forecast for 2009. The expectation is that total billed customer attachment growth over the next eight months will wane. This is due to:

1) Much lower customer attachments as indicated by the building permit data.
2) Significantly higher customer attrition arising from the deep recession that thwarts customer attachment related growth.

Customer attrition is expected to rise due to commercial and industrial bankruptcies, manufacturing sector plant closures and higher (double digit) unemployment levels. Significantly lower manufacturing shipments to the United States and auto industry restructuration will impact the commercial and industrial customer base. This attrition has not yet manifested itself since the recession in Ontario became clearly observable in the first several months of the current year; it is expected that customer attrition will rise over the remaining months of the year. Furthermore, this summer and during the new heating season this fall, many residential customers will face financial hardship and customer attrition related to credit non payment is expected to rise.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 26

Question:

Union forecasted short-term transportation and exchange revenues of $18 million in 2009. This is a $5 million reduction from 2008 actual revenue. Union stated, "*The 2009 forecast reflects Union's continued focus and proactive approach to optimization of transportation assets by selling services early in 2008, prior to the precipitous decline in the markets and commodity prices. Those contracts will sustain higher revenues into the 2009 winter season*".

a) Please explain how Union's proactive approach to the optimization of transportation assets would result in a reduction of 2009 short-term transportation and exchange revenues.

Response:

The evidence at the above-noted reference explains that while the 2009 transportation and exchange revenues are projected to be lower than the 2008 actuals, had Union not been proactive in its approach, the 2009 revenues would have been lower than forecast. Specifically, given that Union proactively sold transport and exchange services in 2008 for terms that extended into 2009 prior to a deterioration of the economy and commodity prices, 2009 revenues will reflect these higher market values.

B2 - CME

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters

Ref: Exhibit A, Appendix B, Schedule 1 - "Earninqs Sharinq Calculation"
Exhibit A, Appendix B, Schedule 2 - "Off-Ramp Calculation"

Question:

Please provide an "Earnings Sharing Calculation" in the format of Exhibit A, Appendix B, Schedule 1, and an "Off-Ramp Calculation" in the format of Exhibit A, Appendix B, Schedule 2 using the following assumptions:

a) Each of the "Adjustments" in Column C, in Lines 1, 5, 6 and 8, consisting of the "Accounting adjustment", the "Unaccounted for Gas normalization adjustment", the "Donations", "EB-2008-0304 costs", and "Customer deposit interest" amounts in each Schedule are removed;

b) The Ratepayers' share of earnings, producing 100 basis points of ROE above the benchmark ROE of 10.81 %, is 50%; and

c) The Ratepayers' share of earnings, producing an ROE in excess of 11.81%, is 100%.

Response:

a) b) c) As outlined at Exhibit A, pages 12 - 14, Union's position is that these adjustments are appropriate.

Please see Attachments 1 and 2.

Filed: 2009-04-21
EB-2009-0101
Exhibit B
Tab 2
Schedule 1
Attachment 1

UNION GAS LIMITED
Modified Earnings Sharing Calculation as per CME Question #1
Year Ended December 31, 2008

Line No	Particulars ($000's)	2008 (a)	Non-Utility Storage (b)	Adjustments (c)		2008 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Operating revenue	$ 1,869,283	$ -	$ -	i	1,869,283
2	Storage & Transportation	243,317	78 230	-		165,087
3	Other	33 818	-	(7 530)	ii	26 288
4		2 146 418	78 230	(7 530)		2 060 658
	Operating Expenses:					
5	Cost of gas	1,171,320	8,082	-	iii	1,163,238
6	Operating and maintenance expenses	335,115	12,028	-	iv	323 087
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	-	v	-
9	Property and capital taxes	65 895	953	-		64,942
10		1,757,549	26 029	-		1,731 520
11	Earning Before Interest and Taxes	$ 388 869	$ 52,201	$ (7 530)		$ 329,138
	Financial Expenses:					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					182,787
16	Income taxes					32,531
17	Preferred dividend requirements					5,088
18	Utility earnings					145,168
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Earnings subject to sharing					$ 163,328
23	Common equity					1,205,196
24	Return on equity (line22 / line 23)					13.55%
25	Benchmark return on equity					10.81%
26	50% Earnings sharing %					1.00%
27	100% Earnings to ratepayer % (line 24 - line 25 - line 26)					1.74%
28	50% Earnings sharing $ (line 26 x line 23 x 50%)					6,026
29	100% Earnings to ratepayer $ (line 27 x line 23)					20,995
30	Total earnings sharing $ (line 28 + line 29)					27 021
31	Pre-tax earnings sharing (line 30 / (1 minus tax rate))					$ 40 632

Notes:

i) Accounting adjustment

ii) Shared Savings Mechanism

iii) Unaccounted for Gas normalization adjustment

iv)	Donations	-
	EB-2008-0304 costs	-
		-

v) Customer deposit interest

UNION GAS LIMITED
Modified Off-Ramp Calculation as per CME Question #1
Year Ended December 31, 2008

Line No	Particulars ($000's)	2008 (a)	Non-Utility Storage (b)	Adjustments (c)		2008 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Operating revenue	$ 1,869,283	$ -	$ (6,881)	i	1,862,402
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(14,411)		2,053,777
	Operating Expenses:					
5	Cost of gas	1,171,320	8,082	-	iii	1,163,238
6	Operating and maintenance expenses	335,115	12,028	-	iv	323,087
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	-	v	-
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	-		1,731,520
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (14,411)		$ 322,257
	Financial Expenses:					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					175,906
16	Income taxes					30,225
17	Preferred dividend requirements					5,088
18	Utility earnings					140,593
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Net earnings					$ 158,752
23	Common equity					1,205,196
24	Return on equity (line22 / line 23)					13.17%
25	Benchmark return on equity					11.81%
26	Sufficiency / (Deficiency) % (line 24 minus line 25)					1.36%
27	Sufficiency / (Deficiency) $ (line 26 X line 23)					16,419
28	Pre-tax sufficiency / (deficiency) (line 27 / (1 minus tax rate))					$ 24,690

Notes

i)	Weather normalization adjustment	(6,881)
	Accounting adjustment	-
		(6,881)
ii)	Shared Savings Mechanism	
iii)	Unaccounted for Gas normalization adjustment	
iv)	Donations	-
	EB-2008-0304 costs	-
		-
v)	Customer deposit interest	

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters

Ref: Exhibit A, Appendix B, Schedule 1 - "Earnings Sharing Calculation"
Exhibit A, Appendix B, Schedule 2 - "Off-Ramp Calculation"

Question:

Please indicate the extent to which the Earnings Sharing Amount and Off-Ramp Amount provided in response to Interrogatory No. 1 will increase if the Board determines Union's Actual Distribution Revenue Sufficiency for 2008 to be $72.8M, shown in Line 12 of Column C in Table 1 at Exhibit A, page 4, instead of the $66.6M shown at Line 14 in Columns Band C of Table 1.

Response:

The sharing of storage margins has already been addressed by the Board in the NGEIR Decision (EB-2005-0551), pages 99-107. Using a sufficiency of $72.8 million rather than $66.6 million would not be appropriate as distribution rates in 2008 were adjusted to reflect a change in the sharing of storage premiums as per the NGEIR Decision (75%/25% on long term services for 2008 and 71.1%/28.9% on short term services). This results in the subsidy built into 2008 distribution rates being $27.3 million, not $33.5 million.

If $33.5 million was used as the storage premium adjustment rather than $27.3 million, the sufficiency would increase by $6.2 million. If this amount was shared on a basis consistent with the response provided at Exhibit B, Tab 2, Schedule 1, 100% would go to ratepayers.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters

Ref: Exhibit A, Appendix B, Schedule 1 - "Earnings Sharing Calculation"
Exhibit A, Appendix B, Schedule 2 - "Off-Ramp Calculation"

Question:

Please provide a copy of the materials which Union produced at the Information Session held on Wednesday, April 8, 2009.

Response:

Please see Attachment.

Filed: 2009-05-21
Exhibit B
Tab 2
Schedule 3
Attachment

Information Session
on
2008 Earnings Sharing
EB-2009-0101

Wednesday, April 8, 2009

EB-2007-0606 IR Settlement Agreement

The approved Settlement Agreement provides for the following:

At Section 10.1, an Earnings Sharing Mechanism

"... based on actual, utility earnings. If in any calendar year Union's actual utility return on equity is more than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers... All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation.

Parties acknowledge that the DSM related Shared Savings Mechanism (SSM) and Lost Revenue Adjustment Mechanism (LRAM) and storage related deferral accounts are outside of the earnings sharing mechanism identified above."

At Section 9.1, a Review of the IR Mechanism

"...if there is a 300 basis point or greater variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, Union will file an application to the Board, with appropriate supporting evidence, for a review of the price cap mechanism."

union

Summary of 2008 Actual Results

• Benchmark return on equity ("ROE")	8.81%
• Actual 2008 ROE	12.49%
• Basis points above benchmark ROE	368
• Sharing threshold basis points (IR Settlement Agreement s.10.1) – Customers receive one half of actual earnings over the sharing threshold.	200
• Earnings Sharing Result	$15.2 million

union gas

Summary of 2008 Normalized Results

• Weather Normalized Results ROE	12.11%
• Basis points above benchmark ROE	330
• IR Review Threshold (IR Settlement Agreement s.9.1)	300

- Union's evidence supports the continuation of the existing IR framework without amendments to the current parameters or the base (2007 Board approved) upon which rates are set.

union gas

Calculation of 2008 Revenue Deficiency/(Sufficiency)

Particulars ($ millions)	Board Approved 2007	Actual 2008	Increase/ (Decrease)
	(a)	(b)	(c)
Gas sales and distribution revenue	1,796.8	1,865.6	
Cost of gas	1,134.3	1,178.9	
Gas distribution margin	662.5	686.7	24.2
Transportation	127.4	165.1	37.7
Other revenue	24.4	26.3	1.9
Expenses	567.4	568.3	0.9
Income taxes	8.7	26.1	17.4
Utility income	238.1	283.8	45.7
Cost of capital	259.5	257.6	(1.9)
Revenue deficiency/(sufficiency) after tax	21.4	(26.2)	(47.6)
Provision for income taxes on deficiency/ (sufficiency)	12.1	(13.2)	(25.3)
Distribution revenue deficiency/(sufficiency)	33.5	(39.3)	(72.8)
Storage premium adjustment	33.5	27.3	(6.2)
Total revenue deficiency/(sufficiency)	0.0	(66.6)	(66.6)
Rate Base	3,270.9	3,347.8	76.9

Main Drivers:
2007 Board Approved vs. 2008 Actual Earnings

union gas

($ millions)		Board Approved 2007	Actual 2008	Increase/ (Decrease)
Gas Distribution Margin		$662.5	$686.7	$24.2
Cost of Gas				$4.6
General Service Revenue • Colder than normal weather • Rate class migration • Other (customer additions, NAC variances, non DSM energy conservation, AU factor and unbilled revenue accrual)	 $3.6 $2.1 $4.0			$9.7
Infranchise Contract Delivery Revenue • Two new gas fired power generator plants • OPG Lennox • Increased net production (steel, greenhouse and other) • Rate class migration • Permanent demand destruction	 $3.2 $2.6 $9.2 ($2.1) ($3.0)			$9.9

Main Drivers:
2007 Board Approved vs. 2008 Actual Earnings

($ millions)		Board Approved 2007	Actual 2008	Increase/ (Decrease)
Transportation Revenue		127.4	165.1	37.7
• Short-Term Transportation and Exchange Revenue	$23.3			
• Long-Term Transportation	$14.5			

Main Drivers:
2007 Board Approved vs. 2008 Actual Earnings

union

($ millions)		Board Approved 2007	Actual 2008	Increase/ (Decrease)
Expenses		$662.5	$686.7	$0.9
• Depreciation increase (TFEP Expansion)	$6.5			
• O & M reductions	($2.9)			
• Property & Capital Taxes reductions	($2.7)			
Income Taxes	$17.4	$8.7	$26.1	$17.4
• Increase due to higher earnings				
Cost of Capital		$259.5	$257.6	($1.9)
• Reductions in interest rates	($8.0)			
• Increases in Rate Base Investment	$6.1			

Main Drivers:
2007 Board Approved vs. 2008 Actual Earnings

union

($ millions)		Board Approved 2007	Actual 2008	Increase/ (Decrease)
Storage Premium Adjustment		$33.5	$27.3	($6.2)
• 2007 Board Approved storage margin for utility services	$33.5			
• NGEIR decision resulted in storage margin for 2008	$27.3			

Calculation of Earnings Sharing

union

- Calculation for earnings sharing based on actual utility earnings.
  - Per the NGEIR decision, revenues and costs for unregulated storage services are excluded from earnings sharing calculation.
  - All revenues and costs allowable under cost of service are to be included in the earnings sharing calculation (s.10.1, Settlement Agreement)
- Calculation for IR review threshold provision is based on actual utility earnings normalized for weather.

(Refer to Appendix B, Schedule 1)

Calculation of Earnings Sharing

union

- Cost of service adjustments to actual utility earnings:

1.	Unbilled customer charge revenue adjustment	$3.6
2.	Norm lization of unaccounted for gas	$15.6
3.	Shared Savings Mechanism incentive payments	$7.5
4.	Charitable donations	$0.4
5.	Reorganization transaction costs	$0.1
6.	Interest on customer deposits	$0.5

(Refer to Appendix B, Schedule 1)

Calculation of IR Review Threshold Provision

- Weather normalized utility earnings.
- Includes all adjustments made to arrive at utility earnings for sharing purposes.
- Normalization adjustment reduces revenues by $6.9 million as a result of colder than normal weather.
- Result:

ROE – IR review threshold	12.11%
ROE Benchmark	8.81%
Basis points above benchmark ROE	330
Basis points – IR review threshold	300

(Refer to Appendix B, Schedule 2)

2009 and 2010 Financial Forecast

Forecast incorporates global economic recession.

- Support no change to the price cap formula or to the base.

- Union is not expected to achieve:
  - Threshold for earnings sharing (200 bp above benchmark ROE).
  - IR review threshold (300 bp above benchmark ROE).

- Forecast incorporates:
  - Fewer housing starts impact on customer additions.
  - Impact of economic recession on commercial and industrial contract demand.

(Refer to Appendix C, Schedule 1 for key forecast assumptions)

ROE Overview: 2008 Actuals vs. 2009 Forecast and 2009 Forecast vs. 2010 Forecast

2008 Actual ROE	12.49%
2009 Benchmark ROE	8.47%
2009 Forecast ROE	9.92%
2010 Forecast ROE	8.66%

(Refer to Appendix C, Schedule 2)

Main Contributors to Reduction in ROE: 2008 Actuals vs. 2009 Forecast and 2009 Forecast vs. 2010 Forecast

union

($ millions)	Actual 2008	Forecast 2009	Forecast 2010	Variance 09 vs 08	Variance 10 vs 09
Gas Sales Margin	687	683	677	(3)	(7)
General Service	571	569	571	(2)	2
• Lower growth in billed customers					
• Customer attrition from commercial bankruptcies, plant closures and credit issues					
Infranchise Contract	127	121	118	(6)	(3)
• Continued gas fired power generation		$3.9	$6.1		
• OPG Lennox		($2.5)	($2.6)		
• Decreased net production (steel, greenhouses, other)		($3.8)	($4.2)		
• Permanent demand destruction		($3.8)	($8.4)		

Main Contributors to Reduction in ROE: 2008 Actuals vs. 2009 Forecast and 2009 Forecast vs. 2010 Forecast

union

($ millions)	Actual 2008	Forecast 2009	Forecast 2010	Variance 09 vs 08	Variance 10 vs 09
Core Services	140	144	147	4	3
Transactional Services	26	21	17	(5)	(4)
Short-Term Transportation and Exchanges	23	18	14	(5)	(4)
Other	3	3	3	0	0
Transportation Revenue	165	165	164	(0)	(0)

Drivers of Variances to Expenses

- O & M
  - 2009 and 2010
    - Inflationary increases
    - DSM spending
- Depreciation and Property Tax
  - 2009 and 2010
    - Increased rate base
- Rate Base
  - 2010
    - Capital expenditures
- Capital Taxes
  - 2010
    - Lower capital tax rates

Allocation and Disposition

- Union is proposing disposition of earnings sharing effective July, 1 2009.

- Union is also proposing disposition of $22.5 million of non-gas commodity related deferral account balance effective July 1, 2009.

  - General Service (Rates M1, M2, 01, 10)
    - Temporary delivery price adjustments for the period July 1, 2009 to December 31, 2009.

  - Impact of earnings sharing on residential customer with annual consumption of 2,600 m^3:

Southern	$4.72
Northern and Eastern	$8.13

  - Infranchise contract and exfranchise rate classes will receive a one-time credit on their July bill.

No Need for a Review
IR is Working as Intended

union

- Existing parameters remain appropriate and should not be adjusted.
  - No fundamental flaw in IR framework. 2008 increase in distribution and transportation revenue arose from unusual circumstances.
  - Earnings sharing and IR review thresholds remain in place.
- Recession will result in lower GDF IPI FDD.
  - With fixed productivity factor, rates may decline or at least be flat over IR term.
- OEB, utilities and intervenors invested significant time and effort to arrive at the current IR framework.
- Current IR framework creates an environment of regulatory certainty for Union and customers.
  - Commitment to capital and employment tied to the current IR parameters.
- An assessment of the 5 year parameters based on a single year's results is not appropriate.

Questions?

B3 - FRPO

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Ref: Exhibit A, Page 1 and 12, 13

Question:

For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings.

Please provide Union's specific rationale for why the Unbilled Customer Charge Revenue Adjustment is exempted from the specific commitment not to change accounting practices to reduce earnings as part of the Settlement Agreement.

Response:

Please see Exhibit A, page 12, lines 20-27, and Exhibit A, page 13, lines 1-5. The removal of the impact of this adjustment is consistent with the Settlement Agreement commitments to be consistent with a cost of service application and to not change accounting practices.

The Unbilled Customer Charge Revenue Adjustment was a one-time accounting accrual adjustment which increased actual revenue reported for 2008 in order to catch up prior period estimates. No additional amounts were collected from ratepayers as a result of this accounting accrual. Accordingly, Union has removed the impact of this one-time adjustment from revenue for earnings sharing. Similarly, had the true-up for the number of days unbilled resulted in a one-time accrual that reduced reported revenue in 2008, Union would have needed to make an adjustment for earning sharing such that revenue would not be understated relative to what was collected from customers.

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Ref: EB-2009-0052, B3.1

Question:

Preamble: In EB-2009-0052, FRPO was attempting to understand the calculation of balances that contribute Account No. 179-90 Short-Term Storage and Other Balancing Services and Account No. 179-72 Long-Term Peak Storage Services as their balances affect the resulting earnings provided by Union in EB-2009-0101. To provide clarity for the purpose of understanding the calculations performed by Union, the following questions are submitted: For attachment 1, please expand the table to present the additional detail showing line items for:

- The long-term commodity costs: UFG and compressor fuel, net of customer supplied fuel.
- The long-term demand costs: O&M, depreciation, and property and capital tax.
- The long term asset costs: interest, return and income tax for unregulated assets.

For each variance, please provide an explanation as to the source of the variance and Union's expectation for a continuation of that effect in 2009 and 2010. For attachment 2, please expand the table to present the additional detail showing line items for:

- The short-term commodity costs: unaccounted for gas ("UFG") and compressor fuel.
- The short-term demand costs: operating and maintenance ("O&M"), depreciation, property & capital tax, interest, income taxes, deferred tax drawdown and return.

If variance is not a helpful, please provide an explanation as to the source of the 2008 numbers and Union's expectation for a continuation of that level in 2009 and 2010. Further, please provide a verbal explanation of the process of moving these assets from rate base to ST Services and demonstrate how Union is not recovering the cost in any utility service.

Response:

Please see Attachment 1 and 2 for additional line item detail on short-term and long-term costs.

Attachment 1 and 2 provide detailed calculations of storage margin subject to sharing with ratepayers. The combined 2007 Board approved costs for short and long-term storage services are for storage assets in excess of the 92 PJs set aside for in-franchise growth. 2008 costs for short and long-term storage services, in addition to the costs in excess of the 92 PJs, includes costs related to Union's incremental investments in storage. Costs of revenues are higher than 2008 because, as a result of the NGEIR Decision, Union made "at risk" investments in new storage capacity and third party storage assets. The revenue for both 2007 Board approved and 2008 actuals are consistent with level of cost incurred. Ratepayers are benefiting from these investments through the sharing of storage deferral accounts.

Attachment 2, it appears that Union incurred significant "Asset Costs" over Board-approved in 2008. The 2008 actual costs included as "Asset Costs" are the same types of costs that are included as "Demand Costs" in 2007. Union has attached Schedule 3 to better align cost categories and to provide parties with a better understanding of 2007 Board approved costs when compared to 2008 actual costs.

For the short-term account, the cost variance explanations are as follows:

- Demand costs increased due to 6 PJs of space included in the 2007 long term forecast being sold short term in 2008
- Commodity costs increased due to higher short term activity levels.

Union expects a continuation of similar short-term cost variances from 2007 Board approved in 2009 and 2010.

For the long-term account, the cost variance explanations are as follows:

- Demand costs decreased due to the aforementioned 6 PJs of space included in the 2007 long term forecast actually being sold short term in 2008
- Commodity costs increased due to higher long term activity levels
- Asset related costs increased as a result of investments and additional third party storage costs. Also, income tax expenses are higher as a result of the income tax accounting change as a result of the NGEIR decision. Specifically, deferred tax expenses are recorded as a result of the change in regulation.

Union expects a continuation of similar long-term cost variances from 2007 Board approved in 2009 and 2010.

In the EB-2005-0520 (2007 Rate Case), Union allocated approximately 92 PJs of a total of 162 PJs of storage space to in-franchise customers based on the Board approved allocation methodology. The cost for the 92 PJs remained in Union's 2008 in-franchise delivery rates. The remaining space and associated cost was allocated to ex-franchise storage services.

2007 Board Approved vs. 2008 Actual
Short Term Storage Services

Line No.	Particulars ($000's)	2007 Board Approved	2008 Actual	Variance
1	Revenue			
2	C1 Off-Peak Storage	$1,000	$2,040	$1,040
3	Supplemental Balancing Services	2,000	3,122	1,122
4	Gas Loans	1,000	2,177	1,177
5	Enbridge LBA	75	211	136
6	C1 ST Firm Peak Storage	13,794	15,777	1,983
7	C1 Firm ST Deliverability	92	-	(92)
8	M12 Interruptible Deliverability	-	-	-
9	Total Revenue	17,961	23,327	5,366
10	Costs			
11	Demand			
12	O&M	(175)	(743)	(568)
13	Depreciation	(132)	(498)	(366)
14	Property & Capital Tax	(28)	(102)	(74)
15	Return	(258)	(905)	(647)
16	Income Taxes	(6)	(13)	(7)
17	Total Demand	(599)	(2,261)	(1,662)
18	Commodity			
19	O&M	(74)	-	74
20	UFG	(751)	(3,269)	(2,518)
21	Compressor Fuel	(707)	(2,939)	(2,232)
22	Total Commodity	(1,532)	(6,208)	(4,676)
23	Total Costs (line 17 + line 22)	(2,131)	(8,469)	(6,338)
24	Net Revenue	$15,829	$14,858	($971)

2007 Board Approved vs. 2008 Actual
Long Term Storage Services

Line No.	Particulars ($000's)	2007 Board Approved	2008 Actual	Variance
1	Revenue			
2	Long Term Peak Storage	$42,058	$81,540	$39,482
3	High Deliverability Storage	-	5,554	5,554
4	Total Revenue	42,058	87,093	45,035
5	Costs			
6	Demand			
7	O&M	(5,954)	(9,767)	(3,813)
8	Depreciation	(4,526)	(4,966)	(440)
9	Property & Capital Tax	(923)	(953)	(30)
10	Return	(7,907)	-	7,907
11	Income Taxes	(75)	-	75
12	Total Demand	(19,385)	(15,686)	3,698
13	Commodity			
14	O&M	(955)	-	955
15	UFG	(4,177)	(4,111)	66
16	Compressor Fuel	(3,437)	(3,695)	(258)
17	Customer Supplied Fuel	7,614	6,110	(1,504)
18	Total Commodity	(955)	(1,696)	(741)
19	Asset Costs			
20	O&M	(15)	-	15
21	Depreciation	(12)	-	12
22	Property & Capital Tax	(9)	-	9
23	Return	(248)	(14,348)	(14,100)
24	Income Taxes	(33)	(3,886)	(3,853)
25	Total Asset Costs	(316)	(18,233)	(17,917)
26	Total Costs (line 12 + line 18 + line 25)	(20,654)	(35,615)	(14,962)
27	Net Revenue	$21,405	$51,478	$30,073

2007 Board Approved vs. 2008 Actual
Long Term Storage Services

Line No.	Particulars ($000's)	2007 Board Approved	2008 Actual	Variance
1	Revenue			
2	Long Term Peak Storage	$42,058	$81,540	$39,482
3	High Deliverability Storage	-	5,554	5,554
4	Total Revenue	42,058	87,093	45,035
5	Costs			
6	Demand			
7	O&M	(5,954)	(9,767)	(3,813)
8	Depreciation	(4,526)	(4,966)	(440)
9	Property & Capital Tax	(923)	(953)	(30)
10	Return	(7,907)	-	7,907
11	Income Taxes	(75)	-	75
12	Total Demand	(19,385)	(15,686)	3,698
13	Commodity			
14	O&M	(7,784)	-	7,784
15	UFG	(431)	(4,111)	(3,680)
16	Compressor Fuel	(354)	(3,695)	(3,341)
17	Customer Supplied Fuel	7,614	6,110	(1,504)
18	Total Commodity	(955)	(1,696)	(741)
19	Asset Costs			
20	O&M	(15)	-	15
21	Depreciation	(12)	-	12
22	Property & Capital Tax	(9)	-	9
23	Return	(248)	(14,348)	(14,100)
24	Income Taxes	(33)	(3,886)	(3,853)
25	Total Asset Costs	(316)	(18,233)	(17,917)
26	Total Costs (line 12 + line 18 + line 25)	(20,654)	(35,615)	(14,962)
27	Net Revenue	$21,405	$51,478	$30,073

Filed: 2009-04-26
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Exhibit B
Tab 3
Schedule 2
Attachment 3
Corrected

2007 Board Approved vs. 2008 Actual
Long Term Storage Services - Reclassified Costs

Line No.	Particulars ($000's)	2007 Board Approved	2008 Actual	Variance
1	Revenue			
2	Long Term Peak Storage	$42,058	$81,540	$39,482
3	High Deliverability Storage	-	5,554	5,554
4	Total Revenue	42,058	87,093	45,035
5	Costs			
6	Demand			
7	O&M	(5,969)	(9,767)	(3,799)
8	Depreciation	(4,538)	(4,966)	(429)
9	Property & Capital Tax	(932)	(953)	(21)
10	Return	(8,155)	(14,348)	(6,193)
11	Income Taxes	(108)	(3,886)	(3,778)
12	Total Demand	(19,700)	(33,920)	(14,220)
13	Commodity			
14	O&M	(955)	-	955
15	UFG	(4,177)	(4,111)	66
16	Compressor Fuel	(3,437)	(3,695)	(258)
17	Customer Supplied Fuel	7,614	6,110	(1,504)
18	Total Commodity	(955)	(1,696)	(741)
19	Total Costs (line 12 + line 18)	(20,653)	(35,616)	(14,963)
20	Net Revenue	$21,405	$51,477	$30,072

2007 Board Approved vs. 2008 Actual
Long Term Storage Services - Reclassified Costs

Line No.	Particulars ($000's)	2007 Board Approved	2008 Actual	Variance
1	Revenue			
2	Long Term Peak Storage	$42,058	$81,540	$39,482
3	High Deliverability Storage	-	5,554	5,554
4	Total Revenue	42,058	87,093	45,035
5	Costs			
6	Demand			
7	O&M	(5,969)	(9,767)	(3,799)
8	Depreciation	(4,538)	(4,966)	(429)
9	Property & Capital Tax	(932)	(953)	(21)
10	Return	(8,155)	(14,348)	(6,193)
11	Income Taxes	(108)	(3,886)	(3,778)
12	Total Demand	(19,700)	(33,920)	(14,220)
13	Commodity			
14	O&M	(7,784)	-	7,784
15	UFG	(431)	(4,111)	(3,680)
16	Compressor Fuel	(354)	(3,695)	(3,341)
17	Customer Supplied Fuel	7,614	6,110	(1,504)
18	Total Commodity	(955)	(1,696)	(741)
19	Total Costs (line 12 + line 18)	(20,653)	(35,616)	(14,963)
20	Net Revenue	$21,405	$51,477	$30,072

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Ref: EB-2009-0101 Exhibit A, Appendix A, Schedule 11

Question:

For the Schedule 11, please provide the detail as requested in Interrogatory #2 above identifying and quantifying the demand and commodity line items and describing the source of variance where appropriate. Further, please provide Union's forecast for 2009 and 2010 for each of those respective line items.

Response:

The margins associated with the services included in Exhibit A, Appendix A, Schedule 11 are not subject to deferral. Accordingly, Union does not track the costs associated with these services on an individual basis.

B4 - Kitchener

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 2, lines 17 through 19

Question:

Does Union Gas accept that it has an obligation during the process of establishing base rates and the incentive regulation mechanism to disclose all information which is reasonably available respecting the likelihood of changes in its revenues during the IRM term?

Response:

If Union knew about any material changes to revenue or cost when establishing base rates for the IR or the incentive regulation mechanism, it would disclose them. When setting base rates for the current IR term, Union was not aware of any expected material changes to revenue or costs.

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 4, Table 1

Question:

Please prepare a schedule which classifies the main drivers of Union's total revenue sufficiency in 2008 as due to variances from 2007 base rate assumptions and variances from the components of the IRM formula.

Response:

It is not possible to identify what the variances are that relate to base rate assumptions or components of the IR formula. Union's 2008 revenue sufficiency is related to the revenue and cost variances as explained in the evidence at Exhibit A, pages 3 - 9. Additional information was provided at the Information Session held on Wednesday, April 8, 2009. A copy of the material produced at the Information Session is attached to the response provided at Exhibit B, Tab 2, Schedule 3.

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 5, line 7 through page 6, line 3

Question:

For the drivers of incremental gas distribution margin realized during 2008 in the contract rate classes, were any of them the result of negotiated changes to forecasted levels of service? If so, when were these negotiated changes known by Union for planning purposes?

Response:

Distribution contract parameters, if changed, are typically renegotiated and changed at each contract renewal. The incremental distribution revenue earned in 2008 vs. 2007 Board Approved revenue forecast resulted from either distribution contract parameters that were negotiated prior to the beginning of 2008 or changes in contract customer end-use operation reflecting changed operating circumstances experienced during 2008.

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 5, lines 19 to 20
Exhibit A, page 6, lines 10 to 11

Question:

Union Gas indicates that rate class migration from contract to general service during 2008 resulted in no net change in gas distribution margin, i.e. offsetting impacts of $ 2.1 million. Shouldn't such rate class migration result in higher net gas distribution margin? If not, then why not? What were the reasons for the rate class migration? Is it expected that the customers who migrated from contract to general service will remain on general service for the remainder of the current IRM term? Does Union anticipate further rate class migration of a similar nature to occur during the remainder of the current IRM term?

Response:

No. The impact on the net gas distribution margin is a factor of the customer's load factor, usage pattern and annual volume. At lower volumes, a customer may be cost neutral if they switch to general service. Specifically, customers forecasting lower usage may chose to switch to general service to avoid monthly demand charges and minimum annual volume charges.

Union does not have the specific reasons for each customer's choice to switch from contract to general service (or vice versa). Elements that influence the customer's decision are: economics (what is the overall cost based on forecasted usage); commitment (is there a required contract term and how does it align with the operational needs); and flexibility (what penalties may apply if actual consumption falls below the contracted requirement).

The customer ultimately decides whether to migrate or not. Union, in preparing demand forecasts, recognizes only cases where rate migration is known to occur. It is not possible to predict this out to the end of the current IRM Term. It will be dependent on each customer and any changes that impact their operations and associated natural gas requirements.

The overall expectation is that rate switching will have a minimal impact (if not a slightly negative impact) on revenues as customers seek out the lowest cost service offering that aligns with their operational needs.

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 6, line 17 through page 7, line 20

Question:

For the main drivers of incremental gas transportation revenue realized during 2008, were any of them the result of negotiated changes to forecasted levels of service? If so, when were these negotiated changes known by Union for planning purposes?

Response:

There were no negotiate changes to forecast levels of service in 2008. The incremental transportation revenues were the result of incremental demands and new market opportunities that became available in 2008.

Please see Exhibit B, Tab 1, Schedule 4(a).

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, Page 13, lines 7 through 15

Question:

Union's proposed normalization of UFG for 2008 yields an adjustment of $ 15.6 million to the calculation of utility earnings subject to sharing. This adjustment is significant, for example, in relation to the impact of changes in average use (AU) for Union's rates M1, M2, 01 and 10 as captured by the approved IRM formula and the AU deferral account. Given that the proposed adjustments for normalizing UFG appear to far exceed the impact of changes to AU, please explain why UFG was not identified by Union as a cost that perhaps warranted similar treatment to AU under IRM at the time the mechanism was being developed in EB-2007-0606?

Response:

Average use ("AU") was a component of the proposed incentive regulation pricing formula. UFG was not. Union's incentive regulation evidence proposed that the x-factor used in the pricing formula incorporate a component related to trends in AU. This concept was consistent with the evidence of Pacific Economics Group. During the Settlement Conference it became evident that although parties agreed it would be appropriate to adjust rates to reflect the impact of changes in AU per general service customer, the most acceptable way to do so would be to adjust rates on the basis of actual historical experience and establish a deferral account to capture variances between forecast and observed declines in AU.

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, page 27, line 9 through page 28, line 9

Question:

Please update the table shown on page 2 of Exhibit C15.4 in EB-2007-0606 to include actual data for 2007 and 2008 and forecast data for 2009 and 2010. Please add line 8 to the table to include actual / forecast throughput to in-franchise customers and lines 9 and 10 to include actual / forecast transportation volumes to ex-franchise customers under short-term and long-term contract service, respectively, for the years 2001 through 2010.

Response:

Please see Attachment.

Filed: 2009-04-21
EB-2009-0101
Exhibit B
Tab 4
Schedule 7
Attachment

Line No.		Actual 2001	2002	2003	2004	2005	2006	2007	2008	Forecast 2009	2010
1	Allowed Return on Equity (%)	9.95	9.95	9.95	9.62	9.63	8.89	8.54	8.81	8.47	N/A
2	ROE before earnings sharing	9.30	10.75	12.75	11.36	11.38	8.80	9.99	12.49	9.92	8.66
3	ROE after earnings sharing	9.30	10.75	11.98	11.36	10.79	8.48	9.99	11.65	9.92	8.66
4	Excess Earnings shared with customers (after tax) $ million	-	-	8.30	-	6.27	3.60	-	10.11	-	-
5	Excess Earnings retained by Union (after tax) $ millions	-	-	8.30	-	6.27	3.60	-	34.21	-	-
6	Actual heating degree days	3,748	3,976	4,246	4,126	4,041	3,605	3,928	4,161	N/A	N/A
7	Normal heating degree days	4,288	4,284	4,268	4,170	4,180	4,177	4,139	4,070	4,034	4,023
8	Infranchise throughput (10*6m*3)	13,896	14,883	14,827	14,450	14,198	13,207	13,878	13,844	12,826	13,232
9	Exfranchise short term throughput (10*6m*3)	1,107	1,717	2,437	901	1,700	739	1,682	2,501	2,100	1,350
10	Exfranchise long term throughput (10*6m*3)	17,506	20,630	18,333	21,067	22,032	19,864	22,034	22,681	23,491	23,748

* Note: Customers share in pre-tax earnings

UNION GAS LIMITED

Answer to Interrogatory from
City of Kitchener ("Kitchener")

Ref: Exhibit A, Appendix B, Schedules 1 and 2
Exhibit A, Appendix D, Schedule 1

Question:

Please prepare revised schedules as referenced which eliminate the accounting adjustment of $ 3,654 and UFG normalization adjustment of $ 15,616.

Response:

As outlined at Exhibit A, pages 12-14, Union's position is that these adjustments are appropriate.

Please see Attachments 1 to 3.

UNION GAS LIMITED
Modified Earnings Sharing Calculation as per Kitchener Question #8
Year Ended December 31, 2008

Line No	Particulars ($000's)	2008	Non-Utility Storage	Adjustments		2008 Utility
		(a)	(b)	(c)		(d)= (a)-(b)+(c)
	Operating Revenues					
1	Operating revenue	$ 1,869,283	$ -	$ -	i	1,869,283
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(7,530)		2,060,658
	Operating Expenses					
5	Cost of gas	1,171,320	8,082	-	iii	1,163,238
6	Operating and maintenance expenses	335,115	12,028	(516)	iv	322,571
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	535	v	535
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	19		1,731,539
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (7,549)		$ 329,119
	Financial Expenses					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					182,768
16	Income taxes					32,524
17	Preferred dividend requirements					5,088
18	Utility earnings					145,156
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Earnings subject to sharing					$ 163,316
23	Common equity					1,205,196
24	Return on equity (line22 / line 23)					13.55%
25	Benchmark return on equity					10.81%
26	Earnings sharing % (line 24 minus line 25)					2.74%
27	Earnings sharing $ (line 26 X line 23 X 50%)					16,517
28	Pre-tax earnings sharing (line 27 / (1 minus tax rate))					$ 24,837

Notes:

i) Accounting adjustment

ii) Shared Savings Mechanism

iii) Unaccounted for Gas normalization adjustment

iv)

	Donations	(394)
	EB-2008-0304 costs	(122)
		(516)

v) Customer deposit interest

UNION GAS LIMITED
Modified Off-Ramp Calculation as per Kitchener Question #8
Year Ended December 31, 2008

Line No	Particulars ($000's)	2008 (a)	Non-Utility Storage (b)	Adjustments (c)		2008 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Operating revenue	$ 1,869,283	$ -	$ (6,881)	i	1,862,402
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(14,411)		2,053,777
	Operating Expenses					
5	Cost of gas	1,171,320	8,082	-	iii	1,163,238
6	Operating and maintenance expenses	335,115	12,028	(516)	iv	322,571
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	535	v	535
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	19		1,731,539
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (14,430)		$ 322,238
	Financial Expenses					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					175,887
16	Income taxes					30,219
17	Preferred dividend requirements					5,088
18	Utility earnings					140,580
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Net earnings					$ 158,740
23	Common equity					1,205,196
24	Return on equity (line22 / line 23)					13.17%
25	Benchmark return on equity					11.81%
26	Sufficiency / (Deficiency) % (line 24 minus line 25)					1.36%
27	Sufficiency / (Deficiency) $ (line 26 X line 23)					16,406
28	Pre-tax sufficiency / (deficiency) (line 27 / (1 minus tax rate))					$ 24,671

Notes

i)

	Weather normalization adjustment	(6,881)
	Accounting adjustment	-
		(6,881)

ii) Shared Savings Mechanism

iii) Unaccounted for Gas normalization adjustment

iv)

	Donations	(394)
	EB-2008-0304 costs	(122)
		(516)

v) Customer deposit interest

UNION GAS LIMITED
Modified Allocation of 2008 Earning Sharing to Rate Classes as per Kitchener Question #8

Line No.	Particulars	Rate Class	C2007 Return on Equity Allocation (i) ($000's) (a)	2008 Earning Sharing ($000's) (b)
	Northern & Eastern Operations Area			
1	Small Volume General Firm Service	01	44,549	(4,265)
2	Large Volume General Firm Service	10	8,234	(788)
3	Medium Volume Firm Service	20	4,263	(408)
4	Large Volume High Load Factor Firm Service	100	5,641	(540)
5	Large Volume Interruptible Service	25	1,913	(183)
6	Wholesale Transportation Service	77	8	(1)
7	Total Northern & Eastern Operations Area		64,608	(6,185)
	Southern Operations Area			
8	Small Volume General Service Rate	M1	104,130	(9,969)
9	Large Volume General Service Rate	M2	15,828	(1,515)
10	Firm Industrial and Commercial Contract Rate	M4	4,220	(404)
11	Interruptible Industrial & Commercial Contract Rate	M5A	2,587	(248)
12	Special Large Volume Industrial & Commercial Contract Rate	M7	2,617	(250)
13	Large Wholesale Service Rate	M9	219	(21)
14	Small Wholesale Service Rate	M10	10	(1)
15	S & T Rates for Contract Carriage Customers	T1	12,835	(1,229)
16	S & T Rates for Contract Carriage Customers	T3	1,546	(148)
	Storage and Transportation			
17	Cross Franchise Transportation Rates	C1	186	(18)
18	Storage & Transportation Rates	M12	50,557	(4,840)
19	Transportation of Locally Produced Gas	M13	39	(4)
20	Storage & Transportation Services - Transportation Charges	M16	55	(5)
21	Total Southern Operations Area		194,830	(18,652)
22	Total		259,438	(24,837) (ii)

Notes:
(i) Allocated costs per 2007 Decision in EB-2005-0520
(ii) Earning Sharing balance for Disposition as per EB-2009-0101, Exhibit B, Tab 4, Schedule 8, Attachment A

B5 - LPMA

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 5

Question:

Were the two new gas fired power generation plants operating for the full year in 2008? If not, please indicate how many months each were in operation in 2008.

Response:

No, neither plants operated for the full year. One facility began operation in November 2008. The second facility did not operate in 2008.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 11

Question:

a) Are the O&M expenses allocated to Union's unregulated storage operations based on the 2007 Board approved cost study applied to 2008 costs or to 2007 costs? If the costs are not based on actual 2008 costs, please provide the impact of using actual 2008 costs allocated based upon the 2007 Board approved cost study.

b) Why has Union used incremental O&M attributable to new storage investments made subsequent to the 2007 cost study rather than fully allocated costs related to these new storage investments? What would be the impact of using fully allocated costs rather than incremental costing to the new storage investments made subsequent to the 2007 cost study?

c) Please provide a breakdown of the O&M costs of $12,028 shown in column (b) of Exhibit A, Appendix B, Schedule 1 into the two components of these costs: O&M costs attributable to storage assets included in the 2007 Board approved cost study, and the incremental costs attributable to new storage investment made subsequent to the 2007 cost study.

Response:

a) The O&M expenses are based on 2008 actual costs.

b) "Incremental costs" is in reference to costs incurred post 2007 cost study for the purpose of providing unregulated storage services. All costs, both existing and post 2007 attributed to the unregulated business, are fully allocated.

c) The amount attributable to storage assets post 2007 is $12,568.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 13

Question:

a) What years were used to calculate the UFG volume for test year 2007 in EB-2005-0520?

b) Please provide the impact on the $15.6 million if the following years are used in place of the 2005 through 2007 period:

   i) 2003 through 2005, and
   ii) 2004 through 2006.

c) Please explain in detail the rationale for using a forecast methodology to calculate UFG for 2008 when the actual utility UFG of $44,857 (Exhibit A, Appendix B, Schedule 3) is known.

d) Please indicate what Union means by "normalized" at line 12. What has been normalized and what has it been normalized to?

e) Please specify the part in Section 10.1 of the Settlement Agreement upon which Union is relying to use the weighted average of three years for purposes of calculating the 2008 utility earnings.

f) Please provide examples of Union using the three year weighted average of UFG rather than the actual UFG in reporting on historical costs and utility earnings. In particular, how did Union report actual 2004 utility earnings and costs in EB-2005-0520?

Response:

a) The years used to calculate UFG volume for the test year 2007 in EB-2005-0520 were 2004, 2003 and 2002.

b) Please see Attachments 1 and 2.

c) Please see EB-2009-0101, Exhibit A, Page 13 of 29, Line 7 through 15

Union's rationale for normalizing UFG is provided at Section 10.1 of the EB-2007-0606 Settlement Agreement. The Settlement Agreement states that "those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation".

For a cost of service application, UFG included in rates is determined using the most current three years of actual experience. Consistent with how UFG would be determined in a cost of service proceeding, Union calculated the UFG adjustment for earning sharing using 2005, 2006 and 2007 actual UFG.

d) UFG normalization refers to the established practice of using a weighted average of three years methodology for calculating UFG for a cost of service application.

e) Please see (c) above.

f) Please see the following evidence from Union's 2007 cost of service proceeding (Attachment 3): EB 2005-0520, Exhibit D3 through D6, Tab 2, Schedule 2.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 13

Question:

a) What years were used to calculate the UFG volume for test year 2007 in EB-2005-0520?

b) Please provide the impact on the $15.6 million if the following years are used in place of the 2005 through 2007 period:

i) 2003 through 2005, and
ii) 2004 through 2006.

c) Please explain in detail the rationale for using a forecast methodology to calculate UFG for 2008 when the actual utility UFG of $44,857 (Exhibit A, Appendix B, Schedule 3) is known.

d) Please indicate what Union means by "normalized" at line 12. What has been normalized and what has it been normalized to?

e) Please specify the part in Section 10.1 of the Settlement Agreement upon which Union is relying to use the weighted average of three years for purposes of calculating the 2008 utility earnings.

f) Please provide examples of Union using the three year weighted average of UFG rather than the actual UFG in reporting on historical costs and utility earnings. In particular, how did Union report actual 2004 utility earnings and costs in EB-2005-0520?

Response:

a) The years used to calculate UFG volume for the test year 2007 in EB-2005-0520 were 2004, 2003 and 2002.

b) Please see Attachments 1 and 2.

c) Please see EB-2009-0101, Exhibit A, Page 13 of 29, Line 7 through 15

Union's rationale for normalizing UFG is provided at Section 10.1 of the EB-2007-0606 Settlement Agreement. The Settlement Agreement states that "those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation".

For a cost of service application, UFG included in rates is determined using the most current three years of actual experience. Consistent with how UFG would be determined in a cost of service proceeding, Union calculated the UFG adjustment for earning sharing using 2005, 2006 and 2007 actual UFG.

d) UFG normalization refers to the established practice of using a weighted average of three years methodology for calculating UFG for a cost of service application.

e) Please see (c) above.

f) Please see the following evidence from Union's 2007 cost of service proceeding: EB 2005-0520, Exhibit D3 through D6, Tab 2, Schedule 2.

UNION GAS LIMITED
Modified Unaccounted for Gas Volume for LPMA Question #3 (b) (i)
For the Year Ending December 31, 2008

Line No.	Particulars	(a)	(b)	(c)
	Determination of normalized UFG volume for 2008			
	3 year average of actual UFG (10^3 m^3):			
		Volume	Weighting	Volume Weighted
1	2005	174,342	50%	87,171
2	2004	176,650	33%	58,883
3	2003	108,819	17%	18,137
4		Average actual UFG volume		164,191
	3 year average of actual throughput (10^6 m^3):			
5	2005	33,455	50%	16,728
6	2004	31,862	33%	10,621
7	2003	30,605	17%	5,101
8		Average actual UFG throughput		32,450
9	UFG ratio for 2008			0.506%
10	2008 actual throughput (10^6 m^3)			34,978
11	Normalized UFG volume for 2008 (10^3 m^3)			176,982
	Unregulated allocation			24,954
	Normal Utility UFG volume			152,028

Monthly	Throughpu	Ratio	UFG	Non Utili	Utility UF(	WACOG	UFG $
Jan	5,133	0.506%	25,972	3,662	22,310	307.435	6,859
Feb	3,658	0.506%	18,509	2,610	15,899	307.435	4,888
Mar	4,068	0.506%	20,583	2,902	17,681	307.435	5,436
Apr	2,265	0.506%	11,460	1,616	9,845	343.057	3,377
May	2,010	0.506%	10,170	1,434	8,736	343.057	2,997
Jun	1,868	0.506%	9,452	1,333	8,119	343.057	2,785
Jul	1,942	0.506%	9,826	1,385	8,441	427.814	3,611
Aug	1,917	0.506%	9,700	1,368	8,332	427.814	3,565
Sep	1,945	0.506%	9,841	1,388	8,454	427.814	3,617
Oct	2,365	0.506%	11,966	1,687	10,279	384.627	3,954
Nov	3,357	0.506%	16,986	2,395	14,591	384.627	5,612
Dec	4,450	0.506%	22,516	3,175	19,341	384.627	7,439
	34,978		176,982	24,954	152,028		$ 54,139
						Actual Utility UFG	44,857
						Normalization Adjustment	$ 9,282

UNION GAS LIMITED
Modified Unaccounted for Gas Volume for LPMA Question #3 (b) (ii)
For the Year Ending December 31, 2008

Line No.	Particulars	(a)	(b)	(c)
	Determination of normalized UFG volume for 2008			
	3 year average of actual UFG (10^3 m^3):			
		Volume	Weighting	Volume Weighted
1	2006	154,015	50%	77,008
2	2005	174,342	33%	58,114
3	2004	176,650	17%	29,442
4		Average actual UFG volume		164,564
	3 year average of actual throughput (10^6 m^3):			
5	2006	29,843	50%	14,922
6	2005	33,455	33%	11,152
7	2004	31,862	17%	5,310
8		Average actual UFG throughput		31,384
9	UFG ratio for 2008			0.524%
10	2008 actual throughput (10^6 m^3)			34,978
11	Normalized UFG volume for 2008 (10^3 m^3)			183,409
	Unregulated allocation			25,861
	Normal Utility UFG volume			157,548

Monthly	Throughpu	Ratio	UFG	Non Utilit	Utility UF(	WACOG	UFG $
Jan	5,133	0.524%	26,915	3,795	23,120	307.435	7,108
Feb	3,658	0.524%	19,181	2,705	16,476	307.435	5,065
Mar	4,068	0.524%	21,331	3,008	18,323	307.435	5,633
Apr	2,265	0.524%	11,877	1,675	10,202	343.057	3,500
May	2,010	0.524%	10,540	1,486	9,053	343.057	3,106
Jun	1,868	0.524%	9,795	1,381	8,414	343.057	2,886
Jul	1,942	0.524%	10,183	1,436	8,747	427.814	3,742
Aug	1,917	0.524%	10,052	1,417	8,635	427.814	3,694
Sep	1,945	0.524%	10,199	1,438	8,761	427.814	3,748
Oct	2,365	0.524%	12,401	1,749	10,652	384.627	4,097
Nov	3,357	0.524%	17,603	2,482	15,121	384.627	5,816
Dec	4,450	0.524%	23,334	3,290	20,044	384.627	7,709
	34,978		183,409	25,861	157,549		$ 56,105
						Actual Utility UFG	44,857
						Normalization Adjustment	$ 11,248

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2007

Line No.	Particulars	(a)	(b)	(c)
	Determination of UFG volume for 2007 (1)			
	3 year average of actual UFG (10^3 m^3)			
		Volume	Weighting	Volume Weighted
1	2004	176,650	50%	88,325
2	2003	108,819	33%	36,273
3	2002	109,942	17%	18,324
4	Average actual UFG volume			142,922
	3 year average of actual throughput (10^6 m^3):			
5	2004	31,862	50%	15,931
6	2003	30,605	33%	10,202
7	2002	31,813	17%	5,302
8	Average actual UFG throughput			31,435
9	UFG ratio for 2007 (2)			0.455%
10	2007 forecast throughput (10^6 m^3)			32,437
11	Estimated UFG volume for 2007 (10^3 m^3) (3)			147,478
12	Estimated UFG for 2007 ($000) (4)			$ 52,424

Notes:
(1) Union proposes no methodology changes in this proceeding for the calculation of UFG.
(2) Line 4 / line 8 / 1,000
(3) Line 9 * line 10 * 1,000
(4) Calculated using EB-2005-0290 reference price of $355.473/$10^3$ m^3

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2006

Line No.	Particulars	(a)	(b)	(c)
	Determination of UFG volume for 2006			
	3 year average of actual UFG (10^3 m^3):			
		Volume	Weighting	Volume Weighted
1	2004	176,650	50%	88,325
2	2003	108,819	33%	36,273
3	2002	109,942	17%	18,324
4	Average actual UFG volume			142,922
	3 year average of actual throughput (10^6 m^3):			
5	2004	31,862	50%	15,931
6	2003	30,605	33%	10,202
7	2002	31,813	17%	5,302
8	Average actual UFG throughput			31,435
9	UFG ratio for 2006 (1)			0.455%
10	2006 forecast throughput (10^6 m^3)			31,303
11	Estimated UFG volume for 2006 (10^3 m^3) (2)			142,322
12	Estimated UFG for 2006 ($000) (3)			$ 50,592
13	Intraperiod WACOG adjustment ($000)			$ (6,573)
14	Net estimated UFG for 2006 ($000)			$ 44,019

Notes:
(1) Line 4 / line 8 / 1,000
(2) Line 9 * line 10 * 1,000
(3) Calculated using EB-2005-0290 reference price of $355.473/$10^3$ m^3

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2005

Line No.	Particulars	(a)	(b)	(c)
	Determination of UFG volume for 2005			
	3 year average of actual UFG (10*3m*3):			
		Volume	Weighting	Volume Weighted
1	2002	109,942	50%	54,971
2	2001	184,102	33%	61,367
3	2000	155,948	17%	25,991
4	Average actual UFG volume			142,329
	3 year average of actual throughput (10*6m*3):			
5	2002	31,813	50%	15,907
6	2001	27,355	33%	9,118
7	2000	30,522	17%	5,087
8	Average actual UFG throughput			30,112
9	UFG ratio for 2004 (1)			0.473%
10	2004 forecast throughput (10^6 m^3)			31,180
11	Estimated UFG volume for 2005 (10^3 m^3) (2)			147,377
12	Estimated UFG for 2005 ($000) (3)			$ 51,363
13	Intraperiod WACOG adjustment ($000)			$ (5,548)
14	Net estimated UFG for 2005 ($000)			$ 45,815

Notes:
(1) Line 4 / line 8 / 1,000
(2) Line 9 * line 10 * 1,000
(3) Calculated using EB-2004-0499 reference price of $352.996/10*3m*3 for January to March ; EB-2005-0232 reference price of $322.784/10*3m*3 for April to June ; and EB-2005-0290 reference price of $355.473/10*3m*3 for July to December.

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2004

Line No.	Particulars	(a)	(b)	(c)
	Determination of UFG volume for 2004			
	3 year average of actual UFG (10^3 m^3):			
		Volume	Weighting	Volume Weighted
1	2002	109,942	50%	54,971
2	2001	184,102	33%	61,367
3	2000	155,948	17%	25,991
4		Average actual UFG volume		142,329
	3 year average of actual throughput (10^6 m^3):			
5	2002	31,813	50%	15,907
6	2001	27,355	33%	9,118
7	2000	30,522	17%	5,087
8		Average actual UFG throughput		30,112
9	UFG ratio for 2004 (1)			0.473%
10	2004 forecast throughput (10^6 m^3)			31,180
11	Board Approved UFG volume for 2004 (10^3 m^3) (2)			147,377
12	Actual UFG volume for 2004 (10^3 m^3)			176,650
13	Actual UFG ($000) (3)			$ 55,660
14	Intraperiod WACOG adjustment ($000)			$ 621
15	Net actual UFG for 2004 ($000)			$ 56,281

Notes:
(1) Line 4 / line 8 / 1,000
(2) Line 9 * line 10 * 1,000
(3) Calculated using EB-2003-0287 reference price of $265.236/$10^3$ m^3 for January to March ; EB-2004-0210 reference price of $297.320/$10^3$ m^3 for April to June ; EB-2004-0267 reference price of $334.670/$10^3$ m^3 for July to September ; and EB-2004-0416 reference price of $335.726/$10^3$ m^3 for October to December.

UNION GAS LIMITED
Actual Unaccounted for Gas Volumes
Years Ending December 31, 2000-2004

Line No.	Particulars (10^3 m^3)	Board Approved	Actual
1	2000	169,646	155,948
2	2001	196,453	184,102
3	2002	189,396	109,942
4	2003	190,043	108,819
5	2004	147,377	176,650

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 17

Question:

At what level would the X factor have had to been in 2008 to reduce the normalized return on equity of 12.11% to the benchmark ROE of 8.81%?

Response:

The X factor would have had to be 8.72%.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 19

Question:

The evidence states that "the recession will also result in lower GDP IPI FDD over the remainder of the IR term."

a) What is the GDP IPI FDD factor Union is forecasting to be applicable to the 2010 rates?

b) What are the GDP IPI FDD figures as reported by Statistics Canada for the third and fourth quarters of 2008 that will be used as part of the determination of 2010 rates?

c) What is the impact on the 2010 ROE of a 0.25% increase in the GDP IPI FDD forecast for 2010?

Response:

a) As noted in Exhibit A, Appendix C, Schedule 1, Union did not include a price cap adjustment (escalation) in the revenue forecast.

b) Q3: 3.0%, Q4: 3.3% are the current reported figures. However, these figures are subject to change by Statistics Canada. The figures that are available at the time the second quarter 2009 figures become available will be used in the determination of 2010 rates.

c) ROE for 2010 would increase by 0.12%.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 22

Question:

Based on the most recent Consensus Forecast available what would the 2010 benchmark ROE be? Please use only the 12 month ahead forecast for 10 year Government of Canada Bonds (i.e. do not average with the 3 month ahead forecast) for this calculation.

Response:

Please see Attachment.

Formula Based Return on Equity (ROE) Calculation

10 Year Consensus Forecast - May 2009		3.20%
Average Spread on 10 & 30 Year Canadian Bonds		0.77%
Average Long Canada		3.97%
Adjustment factor		
Long Canada in E.B.R.O. 499	7.25%	
Average above	3.97%	
	3.28%	
25% of difference		0.82%
Risk Premium		3.55%
Formula Based ROE		8.34%

Notes:

1) As per E.B.R.O. 499 the risk premium was approved at 3.55% @ a Long Canada of 7.25%.
2) The 10 Year Consensus Forecast is per the Consensus Forecasts as published by Consensus Economics, Inc.
3) The average spread on the 10 & 30 year Canadian Bonds rate are as reported in the Financial Post. The average is based on the April spread covering 20 days (April 20 - May 15).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 22

Question:

a) Please reconcile the figure of 3,232 customer additions in 2009 shown at line 20 with the figure of 4,063 shown in Exhibit A, Appendix C, Schedule 1.

b) Which figure has been used in the calculation of the 2009 ROE?

c) What is the most recent year-to-date figure of net attachments in 2009? How does this figure compare to the net attachments at the same time in 2008?

d) Please confirm that the 2008 customer additions figure of 20,069 shown on line 22 is the net customer additions for 2008. If this cannot be confirmed, please provide the net customer additions for 2008 that is comparable to the projected figures for 2009 and 2010 shown in Exhibit A, Appendix C, Schedule 1.

Response:

a) The figure of 3,232 is the year over year increase of the December 2009 customer addition forecast estimate over the actual 2008 December count.

   The annual increase of 4,063 is the year over year increase at December of the 2009 forecast compared to the forecast for year end 2008. The difference between the two numbers represents the 2008 forecast variance that is contained in the 2009 customer forecast.

b) The 2009 ROE calculation is based on customer additions of 4,063.

c) Please see Exhibit B, Tab 1, Schedule 8(b).

d) Confirmed. The figure 20,069 indicates the annual increase in the total number of billed customers measured at year end.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 24 - 25

Question:

Does Union have any potential revenue increases in 2009 and/or 2010 related to new ethanol plants or to expansions at existing ethanol plants? If yes, has this been factored into Union's forecasts?

Response:

Yes. Union has revenue increases in 2009 and 2010 related to new ethanol plants. These increases have been factored into Union's forecasts.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, page 22 - 27

Question:

For each of the categories listed below, please provide the most recent year-to-revenues for 2009 and the corresponding year-to-date revenues for the same period in 2008.

i) General Service Revenues;
ii) Infranchise Contract Delivery Revenue; and
iii) Transportation Revenue.

Response:

Provided below are the year-to-date (as of March 31, 2009) revenues.

Particulars ($millions)	2008 Actual	2009 Actual	Variance
General Service Delivery Revenue	$208.9	$211.1	$2.2
In-franchise Contract Delivery Revenue	34.8	33.4	(1.4)
Transportation Revenue	43.4	51.0	7.6

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, Appendix C, Schedule 2

Question:

Please provide a sensitivity analysis of the impact on the ROE in 2009 and 2010 of the following changes:

a) An increase in net customer attachments in 2009 of 1,000.

b) Salary and wage increase of 2.5% in 2010.

c) A reduction in inflationary increases in 2009 and 2010 to 1.5% per year.

Response:

The impact of the requested sensitivities on ROE is as follows:

	2009	2010
a)	0.00%	0.01%
b)	n/a	0.12%
c)	0.04%	0.04%

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A, Appendix A, Schedule 12

Question:

a) Please explain what is meant by energy management consultancy fees in footnote 2.

b) What is the level of these fees excluded in the 2007 actual figure?

c) Were there any energy management consultancy fees excluded in the actual 2008 figure? If yes, please explain the rationale for excluding these fees in 2008.

Response:

a) The energy management consultancy fees refer to revenue earned from a one-time service that Union provided to a single contract customer. The service ended in May 2008. All fees are included in Appendix A, Schedule 12, line 5.

b) Union earned $343,010 in 2007.

c) Union earned $127,662 in 2008.

B6 - SEC

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A, p. 8

Question:

Please provide a summary of the "increases in rate base investment that increased costs [of capital] by $5.8 million" in 2008.

Response:

Please see Exhibit A, Appendix A, Schedule 18.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A, p. 10 and 16, and Ex. A, Schedule B

Question:

Ex. A, pg. 10 states that "revenues and costs for unregulated storage services are excluded from the earnings sharing calculation." However, at p. 16, the evidence states that "Earnings from utility operations are increased by the portion of the storage premium reflected in approved rates to determine utility earnings subject to sharing....The after tax earnings impact of the premium in 2008 is $10.7 million and $7.5 million respectively." In Exhibit A Schedule B, column 2, it appears that Union has excluded all Storage and Transportation revenues and operating expenses from its utility earnings. At lines 19-21 of the same exhibit appears that certain storage premiums have been added back to utility earnings but it is not clear what the nature of those premiums are (i.e. whether they are in-franchise or ex-franchise).

a) Please clarify the treatment of ex-franchise storage revenues for the purposes of determining Union's earnings subject to earnings sharing.

b) If Union has not included any ex-franchise storage revenues in its earnings calculation, please explain why that is, given that the Board in the NGEIR decision [p. 107] said that Union would continue to share ex-franchise storage margin with ratepayers in 2008, albeit at a reduced rate (75%) from 2007.

c) Please confirm that Column B in Ex. A, Appendix B includes only revenues and costs relating to storage operations and not transportation.

Response:

a) Storage service revenues and costs are subject to deferral account treatment and are not included in the earnings sharing calculation. Transportation service revenues and costs are included in the earnings sharing calculation. As shown at Exhibit A, page 4, Table 1, line 13, and further explained on page 16, a portion of the forecast Board approved net storage margin has been used to subsidize in-franchise rates (i.e. in-franchise rates are lower than they otherwise would be if the subsidy did not exist). As a result the subsidy of $27.3 million (or $18.2 million after-tax) that was built into in-franchise rates must be included in the earnings subject to earnings sharing.

b) Union continues to share ex-franchise storage margin with ratepayers through its deferral accounts 179-70 and 179-72. The amounts in line 2 of Exhibit A, Appendix B, Schedules 1 and 2 are net of amounts in the deferral accounts. To include the gross storage margin would have the effect of sharing the margin through the deferral accounts and again through earnings sharing.

c) Confirmed.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A, Appendix B

Question:

Please provide the cost rate used to calculate the unfunded short-term debt amount (line 13) and state the rationale for the cost rate used.

Response:

Please see Exhibit A, Appendix A, Schedule 4, line 2, column (k).

The 3.03% cost rate is Union's actual 2008 short term debt rate.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A, Appendix B

Question:

a) Please explain the entry at line17: "Preferred dividend requirements", which reduces utility income subject to sharing by $5.1 million. Is this amount an approved element of Union's cost of capital? If not, what is the rationale for including this deduction in calculating Union's income that is subject to sharing?

Response:

Yes. This amount is an approved element of Union's cost of capital. Please see Attachment. Also see Exhibit A, Appendix A, Schedule 4, line 4, column (l).

UNION GAS LIMITED
Summary of Cost of Capital
Year Ending December 31, 2007

Line No	Particulars	Utility Capital Structure ($000's) (a)	(%) (b)	Cost Rate % (c)	Requested Return ($000's) (d)
	As filed				
1	Long-term debt	$ 2,090,667	61 27	7 68%	$ 160,559
2	Unfunded short-term debt	(152,817)	(4 48)	3.16%	(4,831)
3	Total debt	1,937,850	56.79		155,728
4	Preference shares	109,469	3 21	4.71%	5,161
5	Common equity	1,364,880	40.00	9 63%	131,438
6	Total rate base	$ 3,412,199	100 00		$ 292,327
	Per Settlement Agreement				
7	Long-term debt	$ 2,082,334	61 66	7 66%	$ 159,403
8	Unfunded short-term debt	(30,396)	(0.90)	1.55%	(472)
9	Total debt	2,051,938	60 76		158,931
10	Preference shares	109,469	3 24	4 71%	5,161
11	Common equity	1,215,792	36 00	9 63%	117,081
12	Total rate base	$ 3,377,199	100.00		$ 281,173
13	Change (Line 12 - Line 6)	(35,000)			(11,154)
	Per Board Decision				
14	Long-term debt	$ 2,082,334	61 66	7 66%	$ 159,403
15	Unfunded short-term debt	(30,396)	(0 90)	1.55%	(472)
16	Total debt	2,051,938	60 76		158,931
17	Preference shares	109,469	3 24	4 71%	5,161
18	Common equity (1)	1,215,792	36.00	8.54%	103,829
19	Total rate base	$ 3,377,199	100.00		$ 267,920
20	Change (Line 19 - Line 12) (2)	-			(13,252)

Notes

(1) 2007 Return on Equity (ROE) using the Board's ROE Guidelines, updated to reflect the October 2006 Consensus Forecast

(2) 2007 Return on Equity (ROE) change before tax is $20,745

B7 - VECC

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Ref: Exhibit A, page 4, Table 1

Question:

Please add one column to this table showing actual 2007 results.

Response:

Please see attachment.

Table 1
Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2008
($millions)

Line No.	Particulars	Board Approved 2007	Actual 2007	Increase/ (Decrease)
1	Gas sales and distribution revenue	1,796.8	1,811.1	
2	Cost of sales	1,134.3	1,148.0	
3	Gas distribution margin	662.5	663.1	0.6
4	Transportation	127.4	126.3	(1.1)
5	Other revenue	24.4	29.8	5.4
6	Expenses	567.4	551.6	(15.8)
7	Income taxes	8.7	20.3	11.6
8	Utility income	238.1	247.3	9.2
9	Cost of capital	259.5	251.9	(7.6)
10	Revenue deficiency/(sufficiency) after tax	21.4	4.6	(16.8)
11	Provision for income taxes on deficiency/(sufficienc	12.1	2.6	(9.5)
12	Distribution revenue deficiency/(sufficiency)	33.5	7.2	(26.3)
13	Storage premium adjustment	33.5	33.5	0.0
14	Total revenue deficiency/(sufficiency)	0.0	(26.3)	(26.3)

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Ref: Exhibit A, page 6

Question:

a) Please explain what is meant by, and quantify the impact on the 2008 General Service Revenues, of "demand price elasticity related normalized average consumption variances" and "non DSM conservation." Please include Union's estimates of demand price elasticity for delivered gas with this response.

b) Please provide Union's view as to the impact on its net income of a sustained decline in natural gas prices on General Service Revenues in the current economic climate.

c) Please indicate whether Union has estimated an income elasticity of demand for gas distribution services and, if so, provide Union's estimate.

Response:

a) Price elasticity of demand refers to the economic relationship between prices and demand. Price elasticity of demand is measured as a ratio of the percentage change in demand caused by the percentage change in natural gas prices. Union measures energy prices by the total bill amount. The economic relationship is an inverse one, since lower prices increase demand.

   Estimates prepared by Union indicate that the price elasticity in the residential and commercial markets is very inelastic. In the case of the residential market the price elasticity is approximately 0.07 which indicates that a 14% change in natural gas prices effects a 1% change in demand.

   The 2008 forecast volume variance associated with price elasticity for the core market was estimated at 8.7 million cubic metres. This represents 0.2 percent of the total annual throughput volumes in 2008. The difference between actual and assumed prices was about 2 percent.

   Non DSM conservation refers to the energy efficiency index contained the residential demand equations. The index is a weighted measurement of the aggregate furnace efficiency for conventional, mid and high efficiency furnaces. Residential customer surveys provide annual percent share measurements for the three furnace types present in the customer base. The number of surveys undertaken since 1991 equals eleven. The forecast estimate for the 2008 demand forecast assumed an aggregate furnace efficiency of 82.6% and the actual survey based measurement for 2008 was 81.2%, consequently the normalized average consumption per customer was marginally higher by about 6 cubic metres compared to the forecast estimate of about 2,440 cubic metres for all residential customers.

b) A sustained and material decline in natural gas prices, for example greater than 15% per year, would increase both the total throughput volumes and the normalized average consumption per customer. Total delivery revenues before the Average Use ("AU") deferral amount disposal would rise accordingly. The incremental normalized average consumption for each rate class would however reduce the variance in the AU factor. The reduction in the AU factor would ultimately favour the customer under the current Incentive Regulation mechanism. Either the AU deferral amount receivable to Union would become smaller, or the AU deferral amount payable to customers would become larger as determined by the reported rate class AU variance at year end.

c) Union does not have an income elasticity of demand estimate for gas distribution services.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Ref: Exhibit A, page 7
Exhibit A, Appendix A, Schedule 11, line 4

Question:

Union attributes the large 2008 increase in Short-Term Transportation and Exchange Revenue to *"increased customer activity and service values due to colder than normal weather late in the year and new market opportunities. In addition, Union put a greater focus on the gas supply transportation portfolio starting in 2007. This focus continued through 2008. Union also invested in incremental sales staff to capture the incremental revenue opportunities and deliver these services to customers. Union's approach to the marketing of transactional services and the financial results for 2008 were the direct result of the IR framework and the elimination of the transportation deferral accounts."*

a) Please elaborate on the "new market opportunities" that arose in 2008.

b) With the exception of "colder than normal weather late in the year," please indicate why the other drivers of this increase would not be expected to persist in 2009 and 2010.

c) Please provide a comparison of the benefit that Union expects to obtain from its 2008 Short-Term Transportation and Exchange Revenue under the current IRM with the amount it would have received for 2008 if the transportation deferral account 179-69 had not been eliminated (assuming the same 2008 revenues and net of the 2008 incremental costs).

d) Please indicate whether Union's response to the elimination of the transportation deferral accounts and the IR framework would have differed had the deadband for earnings sharing been set at (i) 175 bp, (ii) 150 bp, and (iii) 100 bp. Please explain.

e) Please provide the total increase in costs of the "incremental sales staff" in 2008.

f) Does Union expect to maintain the same level of sales staff dedicated to generating short-term transportation and exchange revenues in 2009 and 2010?

Response:

a) Please see Exhibit B, Tab 1, Schedule 4(a).

b) Short term transportation and exchange revenues are driven by market spreads and market demands. Market spreads (i.e. the difference in value of gas between two delivery points), especially for transportation services, can be unpredictable. It is possible that these market drivers may extend into or repeat in 2009 and 2010 but, as noted, market conditions are difficult to predict.

   The financial crisis in North America has reduced the number of customers/counterparties relative to what existed in 2008. Further, credit constraints have increased borrowing costs and are expected to put downward pressure on transactional service opportunities. The higher costs of doing business have reduced some counterparties capabilities to sustain the historical levels of business or forced them from participating in the natural gas transactional business, while other counterparties have been eliminated from the market.

c) With the elimination of the Transportation & Exchange Services Account, (179-69) and the Other S&T Services Account, (179-73), as part of the IR decision (EB-2007-0606) Union no longer tracks costs related to these services and therefore is unable to replicate the deferral account calculation. Please see Exhibit B, Tab 3, Schedule 3.

d) Union agreed to the earnings sharing mechanism as a component of a comprehensive Settlement Agreement. Union cannot speculate on how it would have responded to the elimination of the transportation deferral accounts under different earning sharing scenarios.

e) Based on the average yearly compensation found in EB-2005-0520, Exhibit D3, Tab 7, Schedule 1, line 6 column (a) the increase in cost to Union of adding incremental sales staff would be approximately $260,000 in 2008.

f) Union added one incremental sales staff in May 2009 and will continue to assess the adequacy of staffing levels relative to the market demands and opportunities. Further, Union has also increased support staff and refocused resources to support this increased level of activity and market opportunities.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Ref: Exhibit A, Appendix C, Schedule 6

Question:

The changes in Salaries and Wages and in Contract Services over the period 2008-2010 reflect lower increases than the increases that would obtain under Union's inflation assumptions

a) Do these changes reflect sustainable productivity improvements that Union expects will benefit ratepayers when Union files its next rebasing application?

b) Please indicate whether Union has identified any other efficiency improvements that it expects will benefit ratepayers when it rebases.

Response:

a) These changes reflect Union's best estimates of O&M expenditures for the 2009 and 2010. They include both sustainable and unsustainable productivity improvements.

b) As Union's EB-2007-0606 evidence indicated, Union views both cost efficiency gains and revenue growth as productivity improvements. Union does not have an estimate of what productivity improvements may be passed on to ratepayers when rates are rebased, although the level of earnings projected for 2009 and 2010 may provide a directional indication.