UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Summary Schedule 2 and Exh C1/Tab 1/Pg 11

Union summarizes its operating and maintenance expense by cost type by year in Exh D1/Summary Schedule 2 and total billed customers in Exh C1, Tab1, Page 11 (Table 2). Please complete the table below.

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
OM&A (in $000s)							
# of customers							
OM&A per customer							

Response:

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Net Utility OM&A ($000's)	318,041	322,731	318,064	349,373	369,470	381,513	390,967
# General Service customers	1,288,836	1,308,905	1,324,543	1,343,305	1,359,576	1,378,795	1,399,086
OM&A per customer ($'s)	246.77	246.57	240.13	260.08	271.75	276.70	279.44

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 2/Pg.4

Union's evidence indicates that inflation will increase costs other than salary, pension/benefits and DSM by $17.5 million in the 2013 Test Year as compared to the 2007 Board approved amount. Union is projecting an average rate of inflation of 2.2%, 2.1% and 2.1% for 2011, 2012 and 2013 respectively.

a) What has been the impact of historical low natural gas prices on Union's operating costs?

b) If possible, please provide the savings achieved as a result of low natural gas prices for the years 2008 to 2011 when compared to the 2007 Board approved budgeted amounts.

c) What impact if any does low natural gas prices have on the inflation outlook for the years 2012 and 2013?

Response:

a) Other than cost of gas (ie. gas purchases, compressor fuel, UFG), historical low natural gas prices impact bad debt expense and own use gas.

b) The estimated savings achieved as a result of low natural gas prices for the years 2008 to 2011 are:

Line No.	Year	Total ($millions)
1	2008	0.7
2	2009	(0.1)
3	2010	2.2
4	2011	1.8

c) Union does not expect any impact on the inflation rate forecast arising from low gas prices. Natural gas is a small contributor in the inflation rate estimation and other items in the index are rising such as oil prices.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 6/Pg.2

Union's evidence states that as part of the Union Gas International Financial Reporting Standards conversion project, it was determined that overhead costs are capital within a regulatory environment, but are expensed in an unregulated environment. As a result, overhead costs was no longer distributed to individual assets, but capitalized to a single asset per functional category as Regulatory Overhead Assets.

a) Union has moved to US GAAP and has filed its current application based on this accounting standard. Why has Union treated this cost category according to International Financial Reporting Standards when all other costs and expenses are according to US GAAP?

b) Does Union intend to reverse the treatment of overhead costs according to US GAAP standards?

c) What would be the impact on capital expenditures and O&M if Union were to treat overhead costs as per US GAAP? Please provide the impacts.

Response:

a) The capitalization of overhead costs ("OH") is in accordance with US GAAP. Union's evidence at Exhibit D1, Tab 6, p.2 outlines how OH is allocated to assets.

   During the work to convert to IFRS, Union planned to implement a dual ledger system that allowed reporting of IFRS from one ledger and OEB reporting from a second ledger. Given the nature of the costs that are capitalized as OH, they did not meet the criteria for capitalization under IFRS, but continued to be capital for OEB reporting. System constraints prevented Union from expensing this amount in the IFRS ledger and distributing it to individual assets in the OEB ledger. The compromise was to capitalize to one asset within each functional area, which is amortized over the average life of the assets within that category. That system configuration change had already been implemented in our accounting system when Union made the decision to transition to US GAAP.

b) Please see the response at a) above.

c) As the current treatment is in accordance with US GAAP, there is no impact to either capital expenditures or O&M.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit D1, Summary Schedule 1

The cost of service summary schedule shows Other Financing as one of the items.

a) What does other financing consist of? Please provide a detailed response.

b) Please explain why other financing is forecasted to increase by more than 275% over the 2007 Board approved amount and by more than 244% over 2011 actual?

Response:

a) Other financing consists of interest on customer deposits and, beginning in 2013, short-term debt arrangement, facility and agency fees.

b) The increase in 2013 of other financing is due to the addition of short-term debt arrangement, facility and agency fees in the amount of $0.817 million. Please see Exhibit E1, Tab 1, Page 7, Lines 5 to 12 for further explanation.

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 5, page 6, Updated

Please provide Union's policies and practices with respect to transportation, mileage reimbursement, accommodations and meals, training & conferences, telecommunications, promotional items and office supplies.

Response:

Please see Attachment 1 and 2 for Union's "Effective Spending" presentation and Travel policy.

Telecommunication Practices

There are a number of cost management practices in place within Union Gas to manage telecommunications costs which are outlined below.

- All employees are required to obtain approval from their manager prior to obtaining wireless devices.
- For Smartphones (including BlackBerry devices) employees must obtain Director level approval.
- Some employees, based on their role, receive a specific device (field employees are provided ruggedized cell phones) in order to communicate remotely, others are allowed to select from a defined list of handsets.
- Guidance is provided by the IT Department as to how the user can minimize costs such as long distance, roaming and other variable charges.
- Wireless telecommunication device users receive monthly detailed cost reports to confirm charges allocated to their department.
- Managers also receive these reports and are accountable for monitoring and ensuring costs are within appropriate levels.

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What All Employees Need to Know About

effective spending

at Union Gas

April 2009

Effective Spending – Why all the effort?

To find new and innovative ways to allow us to conduct our business activities in a more efficient and cost-effective manner

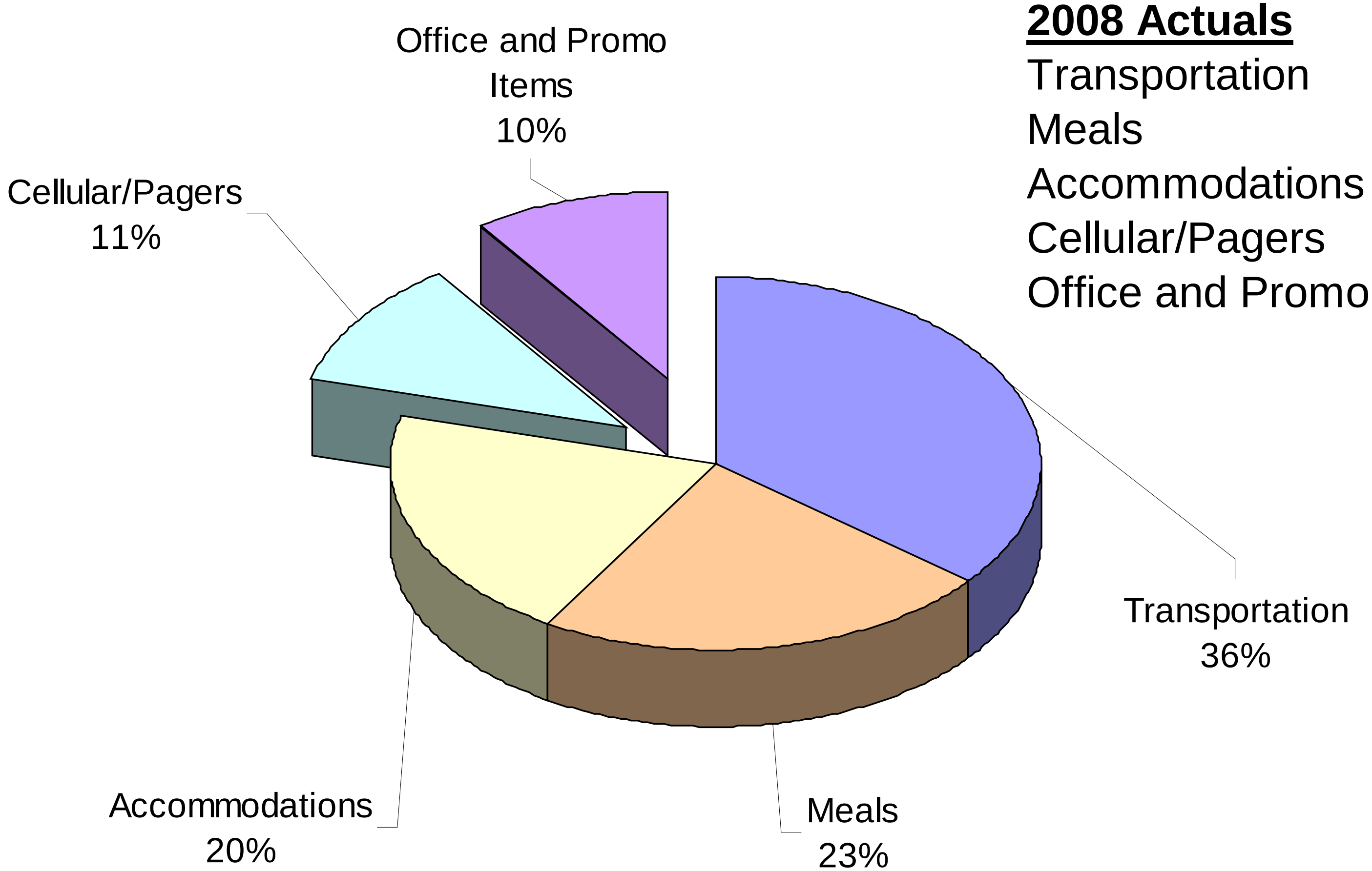
- Employee travel and conferences
  - Business Travel Policy
  - Employee Expense Policy and Procedure
- Conference Approval Process and On-line Calendar
- Telecommunications
- Promotional Items
- Office Supplies

At a Glance

Help me understand….

- How to be most cost effective when travelling on company Business
- How to seek approval to attend a Conference
- How to use the *NEW* on-line Conference Calendar and the benefits
- How to make the best use of telecommunications devices including land lines, cell phones and Blackberries
- What are the requirements when purchasing promotional items
- Hints and tips on how to reduce the use of office supplies
- Where to find related policies on The Source

What are the costs?



2008 Actuals	**$MM**	**%**
Transportation	4.6	36%
Meals	2.9	23%
Accommodations	2.6	20%
Cellular/Pagers	1.4	11%
Office and Promo Items	1.3	10%
	12.8	

Employee Business Travel and Conferences

Content Courtesy of

Union Gas Travel Management Team

Team Members:

Carol Foster, Daylene Turner, Willow Kelly

For More information:

E-Mail: ONT UGL TRAVEL

Phone: (519) 436-4600 Ext. 3005

Business Truel Policy

Spectra Energy Business Travel Policy

- Corporate Travel Arrangements Service Provider - Carlson Wagonlit Travel (CWT)
- Preferred Providers (air travel, hotel accommodations, personal vehicles/rental vehicles)
- Corporate MasterCard
- Employee & Supervisor / Manager responsibilities
  - Use preferred vendors and CWT
  - Understand, comply, manage and control, adhere, ensure

Click here to access the Business Travel Policy

Carlson Wagonlit Travel

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17.4% of our travel spending in 2010 was <u>not</u> administered by our travel service provider Carlson Wagonlit.

Why do we use CWT for all travel arrangements?

- It’s policy
- Reduced rates
- Great service -- 24/7
- Industry experts
- Safety
- Peace of mind
- “Freedom” –upload travel itinerary to Outlook calendar

Carlson Wagonlit Travel

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How do book travel with CWT?

1. Create a Personal Profile (Portrait)
    - Set your preferences
    - In Case of Emergency ("ICE") information
    - Corporate Credit Card on record
    - Designate a travel arranger
    - Can access the on-line booking tool
2. Use the On-line Booking Tool (Concur)
    - Preferred method: Users have instant access to a plethora of travel options which typically results in the traveler choosing the more cost effective reservation.
3. Contact CWT directly
    - Call: 1-800-743-5260
    - Higher service fees to Union Gas

Hotel Accommodations

- Book all hotels through CWT (including group reservations)
- Use preferred hotels unless it is not available or other non-preferred hotels provides better value
- Request standard single room (not suite or business class room)
- Take advantage of complimentary continental breakfast
- Be aware of extra charges
  - Parking, high speed internet, incidentals, availability of free shuttles
- Be aware of cancellation policies
- Pay with Corporate MasterCard
- Opportunities in 2011: block reservations, long-term stays, conferences

Employees can participate in Travel Reward programs.

Air Travel

- Book all flights with CWT
- Adhere to the Business Travel Policy
  - Book early to get best rates
  - Use preferred airlines when the fare they offer is the lowest logical airfare
  - Fly coach class
  - Book non-refundable flights
  - Seek meeting fares when 10 or more employees are travelling
  - Be flexible
  - Pay with Corporate MasterCard

Employees can participate in Travel Reward programs.

Rail Travel

- Book with CWT
- Seating on VIA 1 is permitted. It allows employees to work while in transit and avoid the cost of a meal and possibly transportation to a restaurant
  - Comfortable seating with workspace
  - Includes a meal
  - Allows you to make use of travel time to perform work as required

Rental Car or Personal Vehicle?

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Personal Vehicles

- Should I drive my car or rent a car
- General rule of thumb: If driving more than 125 km/day, the more cost effective option is to rent

Rental Vehicles

- Reserve through CWT
- Use the preferred vendors (Enterprise & National)
- Economical car consistent with requirements of the trip, weather, and road conditions to ensure safety
- Return with full tank of gas
- Pay with Corporate MasterCard
  - Automatically includes insurance coverage therefore, no need to purchase additional insurance coverage from rental company when rental originates in Canada

Corporate MasterCard

Content Courtesy of

Accounts Payable Canada

For More information:

Click on the link above

Corporate MasterCard

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Cardholder Responsibilities	Approver Responsibilities
Ensure receipt of monthly statement	Review transactions for compliance
Reconcile statement with receipts	Ensure all receipts are attached
Detail purpose of trip	Ensure purpose for trip is detailed
List meal attendees	Ensure meal attendees are listed
Detail cash advance spend	Ensure cash advance spend is detailed
Obtain approval prior to monthly deadline	Provide approval prior to monthly deadline

Have you seen ….the Quick Reference Guide for the Corporate MasterCard?
Do you know….. there is a Computer Based Training course available on the Source?

For more information regarding the "Canadian Corporate Credit Card Policy" click here

New Conference Tool & Calendar

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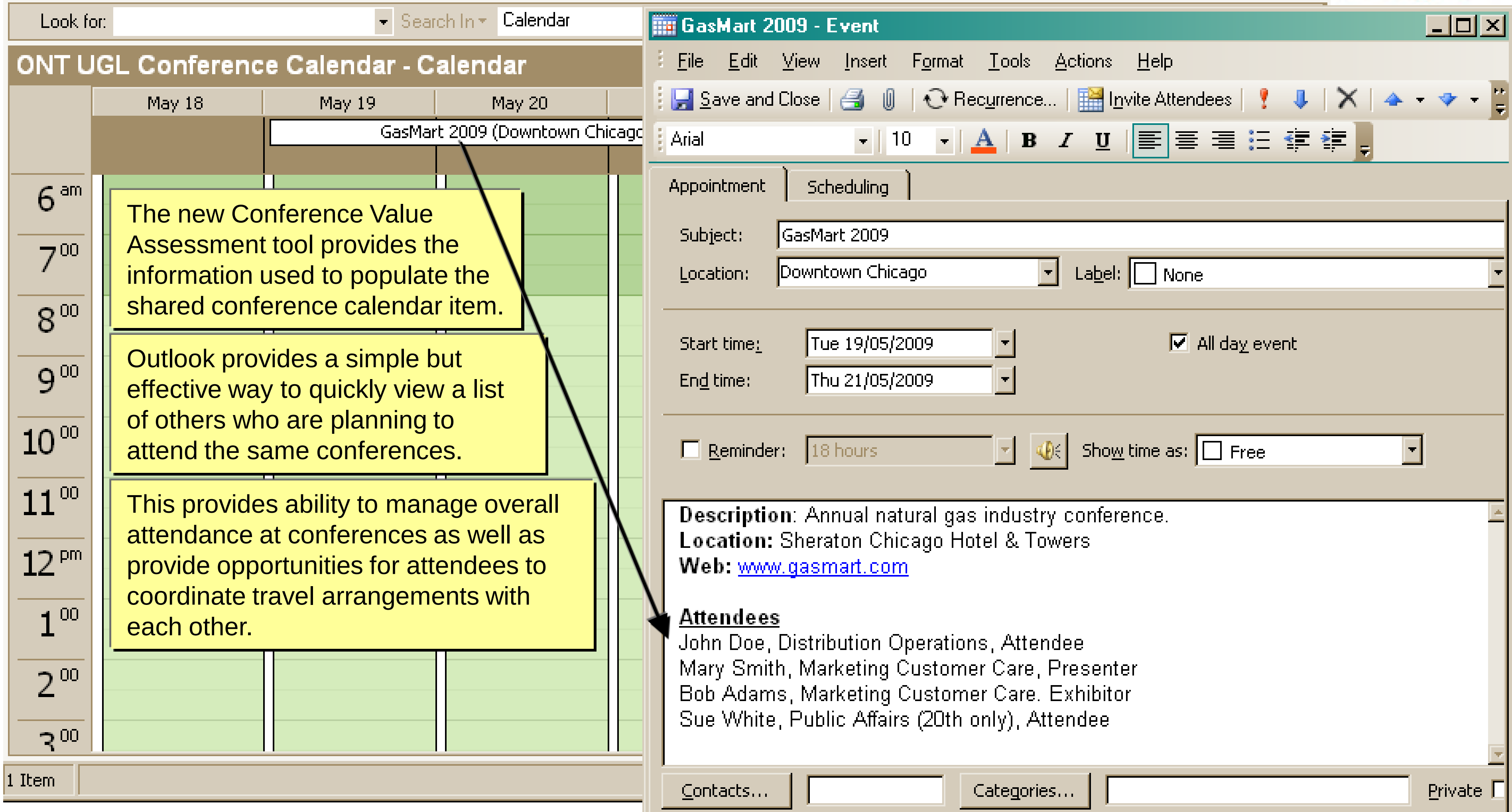
- *NEW* Conference Value Assessment ("CVA") tool and Conference Calendar
- *Process:*
  - Step 1: Complete the CVA tool
  - Step 2: Seek approval from manager
  - Step 3: Once approved, e-mail CVA to "ONT UGL CONFERENCE CALENDAR"
  - Step 4: Book your travel arrangements through CWT and register for conference
- *Benefits*:
  - Supports our 'results focused" return on investment culture
  - Creation of Corporate Conference Calendar to:
    - identify people attending each conferences
    - coordinate travel arrangements to minimize travel costs (car pool, etc)
    - Establish contacts to seek out information after Conference
  - Click here for link to the Conference Value Assessment Tool

Conference Calendar

The new Conference Value Assessment tool provides the information used to populate the shared conference calendar item.

Outlook provides a simple but effective way to quickly view a list of others who are planning to attend the same conferences.

This provides ability to manage overall attendance at conferences as well as provide opportunities for attendees to coordinate travel arrangements with each other.



For instructions on how to access the Conference Calendar, click here

Telecommunications

Content Courtesy of

ITI Services Canada

For More information:

Click on the link above

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Cost Savings Opportunities

- Cell Phones/Blackberries
  - Understand your charges by reviewing billing statements at link below
  - Use your minutes wisely
  - Use calling card or toll-free number when calling long distance
  - Minimize roaming charges
  - Fill out telecom transfer form when someone from your department is leaving
  - Minimize calls to 411
  - Do not call-forward to your cell phone
  - Check cell phone voicemail from landline

For additional information on Telecom & Wireless and Guidelines, visit the ITI site by clicking here.

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Cost Savings Opportunities

- Land Lines
  - Minimize calling 411; use the free web-based www.411.ca instead
  - Use corporate calling card when calling from hotel
  - Use corporate calling card for long distance when away from the office
  - When calling outside of Union Gas, use toll-free numbers when available
  - When teleconferencing, minimize number of lines used by meeting in groups and using speaker phones when possible.

For additional information on Telecom & Wireless and Guidelines, visit the ITI site by clicking here.

Office Supplies

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- Purchase from “Grand and Toy” using Corporate MasterCard
- Use old supplies before ordering new
- Reuse binders and other useful items

- Save files electronically instead of printing
- If printing is required, use double-sided option if available
- Print in colour only when necessary
- For shared documents, circulate or use central posting areas

- For more information:
  - “Waste Reduction – At the Office“ click here
  - “UGL Stationery & General Office Supplies“ ordering click here

Promotional Items

- Use preferred vendors
  - 2 vendors have been chosen to provide Union Gas Limited branded and promotional merchandise:
    - Integrus Brand Solutions Inc.
    - ImageWear by Marks Work Wearhouse
- Before ordering new items, ensure that existing inventory is used
- Be prudent in your spending when making decisions regarding the need to purchase promotional materials
- Buyers of promotional items should use the Corporate MasterCard

- For more details on promotional materials click here

What action can I take now?

- ✓ Book <u>all</u> business travel through CWT using the on-line travel booking tool
- ✓ Use preferred vendors where possible; select lowest fares
- ✓ Book hotel reservations for conferences or long term and group bookings through CWT (even if not preferred vendors)
- ✓ Use the Corporate MasterCard for all travel expenses
- ✓ Use the *NEW* Conference Value Assessment Tool to seek approval for conferences and send your completed CVA Tool to "ONT UGL CONFERENCE CALENDAR"
- ✓ Review your phone, cell and Blackberry use and employ some of the tactics noted here to reduce your costs including minimizing cell phone use and using a Calling Card
- ✓ Create a Effective Spending personal action plan and share it with your team

Together, we can make a difference!

Business Travel Policy

Applicability:	**Applies to Spectra Energy Employees (Canada and US)**
Originator:	**Support Services U.S. and Travel Management Canada**
Approval:	**Group Vice President, Human Resources**
Effective Date:	**03/31/2009**

Statement of Purpose and Philosophy

This policy (and related procedures) was established to ensure that the travel procurement process is conducted in compliance with all laws, regulations, and Spectra Energy standards, and that all travel-related business is conducted in a fair, equitable, and highly ethical manner utilizing appropriate internal controls and best efforts to maintain confidentiality in our dealings with reputable and responsible suppliers.

Policy Expectations

Corporate Travel Arrangements
Employees are required to book business travel arrangements through Spectra Energy's designated travel office or through Spectra Energy's designated online booking tool(s). The company may not reimburse employees for air travel and car rental expenses not secured through the designated travel booking processes.

Preferred Providers
Spectra Energy is continually seeking discount pricing agreements with business travel providers. Employees will be required to use car rental firms and hotels with which the enterprise has corporate or negotiated rates, whenever possible. Employees will be required to use preferred airline carriers for business travel in specified markets based on contractual commitments.

Accountability: Roles and Responsibilities

Support Services U.S. and Travel Management Canada will provide guidance to travelers, travel arrangers, approvers, and auditors on cost-effective management of travel and entertainment expenses. These costs are defined as those that are incurred in order to accomplish business objectives. Corporate Controller-Corporate Controls Group will be consulted on control issues.

Support Services U.S. and Travel Management Canada will be responsible for:

- Ensuring that Spectra Energy maximizes its corporate leverage to reduce business travel costs
- Ensuring that the policy is followed consistently

The CEO and direct reports (and Group VP of HR) can approve individual exceptions to this policy when necessary to accommodate pressing business needs that the designated travel booking processes cannot serve.

Employees traveling on company business are responsible for reviewing and adhering to the enterprise travel procedures located on the Source.

Support Services U.S. and Travel Management Canada will provide periodic reports on compliance to the business units.

Procedure Requirements

Air Travel

Lowest Airfare Policy: Spectra Energy's policy will be to accept the lowest logical airfare available, which meets the employee's time requirements and does not unduly inconvenience the employee. The following criteria defines lowest logical airfare:

- Requires no more than one additional interim stop or connection each way.
- Arrival and departure time is within a one-hour window of the requested departure and arrival time. This includes all connecting and non-stop flights.
- Provides a savings greater than $100 each way.

Preferred Airlines: Spectra Energy is continually seeking discount pricing agreements with airline carriers. Employees will be required to use preferred carriers for business travel in specified markets based on contractual commitments.

Advance Reservations and Discounted Airfares: To take advantage of discounted airfares, business travel must be arranged as far in advance as possible. Employees are encouraged to accept non-refundable, penalty, and Saturday-stay fares when applicable.

Meeting Fares: When 10 or more employees are traveling to the same destination, the meeting coordinator should consult with Support Services U.S. and Travel Management Canada. Oftentimes, meeting fares may be negotiated which can result in significant savings to the enterprise.

Fares Requiring Saturday Night Stayovers: The company will pay for Saturday night stayover expenses when:

- The sum of the fare and the additional expenses (e.g., meals and lodging, but not personal entertainment or sight-seeing expenses) is less than the lowest available airfare not involving a Saturday night stay (as of the date the trip is booked).

  Reimbursements are not allowed for expenses incurred beyond the minimum period required to qualify for the fare.

Personal Travel Vouchers: Reimbursements are not allowed for the use of personal travel vouchers (e.g., frequent flyer certificates) on behalf of business travel.

Private Aircraft: The use of private aircraft for company business is not permitted. A private aircraft is defined as one which the employee owns, leases, or otherwise has available for personal use.

Frequent Flyer Programs: Employees are allowed to participate in frequent flyer programs and retain awards/bonuses; however, employees are not allowed to arrange travel around a frequent flyer program.

In general, the following air travel policy requirements will apply. However, the CEO and direct reports (and the Group VP of HR) will have the option to modify travel policy based on business need.

- **Domestic Air Travel:** All flights within the North American continent are coach class. If coach class is unavailable and it is impractical to delay travel, first class is permitted.

- **International Travel:** All flights to and from the North American continent will be in business class. If business class is unavailable and it is impractical to delay travel, other classes of service will be offered.

- **First Class Travel:** As long as the enterprise incurs no additional expense, first class travel is permitted at the employee's expense and discretion (e.g., free upgrades, use of frequent flyer points).

Airline Club Memberships: Employees are not reimbursed for the cost of airline club memberships.

Cancellations and Unused Tickets: Employees are responsible for ensuring all cancelled and unused tickets are processed for refund in a timely manner and that credits are received in a subsequent company credit card statement for these tickets. Note: For most penalty tickets, the ticket must be cancelled prior to departure in order to receive credit towards the purchase of a future ticket.

Hotel Accommodations
Employees must stay at hotels with which the company has corporate or negotiated rates, whenever possible, unless there are no other alternatives. Good judgment should be used in the hotel selection process.

Hotel Cancellation: Employees are responsible for canceling hotel reservations within the hotel cancellation period to ensure that a "no show" charge will not be assessed.

Hotel Frequent Guest Programs: Employees are allowed to participate in hotel frequent guest programs and retain awards/bonuses; however, employees are not allowed to arrange travel around a hotel frequent guest program.

Using Cars for Company Business

Personal Vehicles
- Employees will be reimbursed at the effective rate (IRS for US, internal calculation for Canada) for use of their personal car on company business in conformance with

business/corporate unit policy. If an employee drives directly from home, the normal commuting mileage is not reimbursed.
- Employees who choose to drive rather than fly will be reimbursed actual mileage or the lowest applicable airfare to the destination, whichever is less.
- When using personal vehicles for company business, the employee is responsible for insurance to cover physical damage, liability, etc.

Rental and Leased Vehicles

Car Rentals: Employees must use car rental firms with which the company has corporate or negotiated rates, whenever possible. Alternate car rental suppliers should only be used when the preferred suppliers cannot accommodate your needs.

- Rental cars should be used when it is more economical than public transportation (including taxi cabs and car service).

- Employees should reserve the most economical car consistent with the requirements of the trip (usually a compact or mid-size car) and weather and road conditions to ensure safety.

Insurance & Vehicle Accident Guidelines for Employees

PREFERED Vendor	**Insurance Guidelines**	**Accident Contact for Insuring Agent**
U.S. employee renting in the U.S	Waive all insurance programs	Employee should call rental company directly
U.S. employee renting in the US and driving across the Canadian border.	Waive all insurance programs – rental benefits are determined based on rental source/pick up location.	Employee should call rental company directly.
U.S employee renting outside the U.S	Buy liability and Collision Damage Waiver (CDW)/ Loss Damage Waiver (LDW)	Employee should call rental company directly
Canadian employee renting in Canada	Use Corporate MasterCard and waive all insurance programs	Employee should call MasterCard for property damage and Cunningham Lindsey for liability claim
Canadian employee renting in Canada and driving across the Canadian border.	Waive all insurance programs – rental benefits are determined based on rental source/pick up	Employee should call rental company directly.

	location.	
Canadian employee renting outside Canada	Buy liability and waive Collision Damage Waiver (CDW)/ Loss Damage Waiver (LDW)	Employee should call MasterCard for property damage and Cunningham Lindsey for liability claim

NON- PREFERED Vendor	**Insurance Guidelines**	**Accident Contact for Insuring Agent**
U.S. employee renting in the U.S	Buy liability and Collision Damage Waiver (CDW)/ Loss Damage Waiver (LDW)	Employee should call rental company directly
U.S employee renting outside the U.S	Buy liability and Collision Damage Waiver (CDW)/ Loss Damage Waiver (LDW)	Employee should call rental company directly
Canadian employee renting in Canada	Use Corporate MasterCard and waive all insurance programs	Employee should call MasterCard for property damage and Cunningham Lindsey for liability claim
Canadian employee renting outside Canada	Buy liability and waive Collision Damage Waiver (CDW)/ Loss Damage Waiver (LDW)	Employee should call MasterCard for property damage and Cunningham Lindsey for liability claim

Accident Guidelines:

1. Rental car insurance tracks the car. If you rent in the US and drive to Canada, you are covered. If you rent in Canada and drive to the US, you are covered.
2. Please contact the insuring agent according to the chart above.
3. For all accidents, an Accident Reporting Form, available from the rental Company, must be completed and submitted to them.
4. All accidents should be reported to your local Environmental Health and Safety (EH&S) representative.
5. For all accidents, please contact the Spectra Corp Insurance Services Group at NTippin@spectraenergy.com.
6. Personal injury to US employees while on company business may be covered by workers compensation. If a US employee is injured on company business please use the claim procedures for workers comp located on the Spectra Source at https://thesource.spectraenergy.com/support/risk/Pages/ClaimsManagement.aspx

7. For Canadian employees involving a third party, the employee must contact Cunningham Lindsey Insurance Adjusters at 1-800-ADJUST4 (1800-235-8784) 24 hours a day, 365 days a year.
8. For Canadian employees with property damage to the rental vehicle please contact the MasterCard claims center directly within (48) hours at 1-866-556-4432 or collect at 1-519-742-4907.

FAQ (Frequently Asked Questions):

1. Do I have to use my Corporate MasterCard to rent vehicles?
   Yes, Employees in US and Canada should use their Corporate MasterCard to rent vehicles. If a Canadian employee does not have a Corporate MasterCard, he should purchase available insurance from the local rental agency. For US employees that do not have a Corporate MasterCard the table above still applies.
2. Do these insurance guidelines apply to contractors? In the US Contractors can waive insurance if they are using a preferred vendor. In Canada, if the contractor has a Corporate MasterCard he can use it for insurance coverage. Otherwise he/she should buy the available coverages from the local rental agency.
3. What if I rent a vehicle outside the US and Canada?
   When renting vehicles outside US and Canada always buy the insurance available from the local rental agency.
4. Canadian citizens renting cars in the U.S. are not permitted to drive the car into Canada; should such an attempt be made, Canadian Customs may seize the car under provisions of that country's import laws. Note that Canadian citizens renting in Canada and crossing into the U.S. are not subject to this restriction.

Rental Car Refueling: Employees are required to refuel the rental car upon return to avoid significant refueling charges imposed by the car rental suppliers.

Note: Personal items left in the rental vehicle are not covered.
<u>Local Rentals: Periodically, it may be appropriate for a business/corporate unit to rent vehicles from local rental companies.</u>

- <u>Intermediate-term (6-11 months) and long-term (12 + months) vehicle requirements should be reviewed with the Fleet Service department responsible for that business/corporate unit for consideration of rental/purchase or conversion from rental to lease.</u>
- Rental/purchase agreements must not be used to circumvent normal company purchasing approval and control policies and procedures for vehicles.

Payment of Business Travel Expenses:
Employees are required to use the designated corporate credit card whenever possible to handle payment of employee business travel expenses.

- The business unit will be responsible for ensuring employees who travel frequently on business are issued a corporate credit card.
- Employees issued a designated corporate credit card are required to use the card for expenses at establishments at which the card is accepted.

Accountability: Roles and Responsibilities
Support Services U.S. and Travel Management Canada will provide guidance to travelers, travel arrangers, and approvers on cost-effective management of travel and entertainment expenses. These costs are defined as those that are incurred in order to accomplish business objectives. Corporate Controller- Corporate Controls Group will be consulted on control issues. Strategic Sourcing has and should be consulted on all purchasing agreements with Preferred Providers.

Compliance

Employees are required to:

- Use preferred suppliers and the Spectra Energy designated travel booking processes.
- Understand and comply with this corporate travel policy to ensure reimbursement for business-related travel and entertainment expenses.
- Manage and control business travel and entertainment costs.
- Adhere to the policy and procedures.
- Ensure business travel and entertainment expenses are appropriate and consistent with business needs.

Managers and supervisors are required to:

- Ensure that employees understand and adhere to the corporate travel policy.

Related Policies, Standards, or Procedures
Employee Expense Policy and Employee Expense Procedure

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, Table 1 & page 3, Updated

a) Please provide a version of Table 1 with the DSM related O&M costs removed from both the 2013 OM&A forecast and the Board-approved 2007 utility O&M.

b) Does the 15.5% reflect a level of DSM spending in 2013 equal to that included in the 2007 Board-approved figure? If yes, please re-calculate the increase in 2013 over the 2007 Board- approved figure with all DSM costs removed from both figures.

c) Please provide the 2007 Board-approved O&M figure excluding all DSM related costs, the 2013 forecast figure based on CGAAP (i.e. no changes for USGAAP) and the corresponding percentage increase between these two figures. Other than the impact on Benefits of difference between CGAAP and USGAAP, do any of the other major drivers change?

Response:

a)

Summary of Utility Increase
Forecast 2013 vs. Board Approved 2007
DSM removed from 2013 and 2007

Line No.	Particulars ($ millions)	
1	Forecast 2013 Utility O&M excluding DSM	361.4
2	Less Cross-Charge	(2.3)
3	Forecast 2013 Utility O&M Less DSM and Cross Charge	359.1
4	Less Board-approved 2007 Utility O&M excluding DSM	(308.6)
5	DSM	-
6	Increase to Utility Costs excluding DSM	50.5

b) The 15.5% does not reflect a level of DSM spending in 2013 equal to that included in the 2007 Board-approved figure. The increase in 2013 over the 2007 Board-approved figure with all DSM costs removed from both figures is 16.4%.

c) The increase in 2013 over the 2007 Board-approved figure with all DSM costs removed from both figures and with the 2013 forecast based on CGAAP is 17.6%. Other than the impact on benefits, none of the other major drivers change.

Summary of Utility Increase
Forecast 2013 vs. Board Approved 2007
DSM removed from 2013 and 2007
CGAAP

Line No.	Particulars ($ millions)	
1	Forecast 2013 Utility O&M excluding DSM	365.3
2	Less Cross-Charge	(2.3)
3	Forecast 2013 Utility O&M Less DSM and Cross Charge	363.0
4	Less Board-approved 2007 Utility O&M excluding DSM	(308.6)
5	DSM	-
6	Increase to Utility Costs excluding DSM	54.4
7	Percentage increase over Board-approved	(17.6%)

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, pages 9 - 10, Updated

a) The evidence indicates that the most significant contributor to the increase of 37 FTEs between 2010 and 2013 relates to seasonal employees that are budgeted in future years but that do not appear in the year end actual FTE count due to the timing of their work engagement. However, the increase of 37 FTE's is based on a 2010 year-end figure. Please explain how the increase of 37 FTE's reflects the seasonal employees if they are not in the 2010 year-end figure? Is the forecast for 2013 FTE's also based on year-end figures or on the year as a whole?

b) Please provide a table for 2007 through 2011 actual and forecasts for 2012 and 2013 for the number of FTE's. If the actual figures are not done on the same basis as the forecasts, please explain the difference (for example year-end vs. annual average).

c) Please provide a further break down of the FTE's in the table requested in part (b) above, into the categories of executive, management, unionized and non-unionized employees.

d) Please provide a further break down of the FTE's in the table requested in part (c) that reflects total FTE's by category, FTE's associated with unregulated activities by category and the net number of FTE's by category related to the operation of the regulated utility.

Response:

a) Of the increase of 37 FTEs from 2010 actual to the 2013 test year, 25 relate to the timing of seasonal employee work engagement (Exhibit D3, Tab 6, Schedule 2).

   The 25 seasonal employees are included in the 2012 and 2013 forecast FTE amount. These employees were not employed as at December 31, 2010 and were therefore not included in the 2010 FTE amount.

b)

UNION GAS LIMITED
FTE 2007-2011

Line No.	Particulars	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Executive	7	5	7	7	7	7	7
2	Management	845	878	910	956	1,003	1,030	1,031
3	Analyst	234	267	272	276	261	277	274
4	Unionized	938	933	899	884	881	914	914
5	Non-Unionized	123	118	95	88	67	91	91
6	Total	2,147	2,201	2,183	2,211	2,219	2,319	2,317
7	Assumed Vacancies in Forecast						(69)	(69)
8	Total	2,147	2,201	2,183	2,211	2,219	2,250	2,248

All figures above (both actual and forecast) are based on year-end amounts.

c) Please see the response at b) above.

d) Union does not track FTE data based on regulated and unregulated activities separately.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, Original & Updated

a) Please explain the following changes between the forecasted and actual results for 2011:

   i) an increase of $11.1 million for salaries/wages;
   ii) an increase of $2.5 million for benefits;
   iii) an increase of $2.8 million for contract services;
   iv) a reduction of $1.1 million for consulting;
   v) a reduction of $1.0 million for affiliate services;
   vi) a reduction of $2.7 million for bad debt.

b) How many months of actual data were included in the 2011 forecast?

c) How much of the increase in salaries/wages of $11.1 million compared to the original 2011 forecast is related to incentive payments?

Response:

a)

i. The increase of $11.1 million for salary and wages is primarily attributed to:
   - Increased costs related to a 2011 incentive pay accrual of $7.0 million;
   - a severance accrual of $1.1 million;
   - overtime of $1.4 million;
   - lower salaries and wages charged directly to capital of $1.8 million;
   - $0.5 million of other small miscellaneous variance;
   - partially offset by a reduction of $0.7 million in contract services.

ii. The increase of $2.5 million for benefits is primarily attributed to:
   - Increased costs related to non pension benefits of $2.8 million and pension benefits of $0.2 million;
   - partially offset by a reduction related to other miscellaneous variances of $0.5 million.

iii. The increase of $2.8 million for contract services is primarily attributed to:
   - Increased costs related to line locates of $0.4 million;
   - $0.2 million for facilities;

- $0.2 million for pipeline integrity;
- repairs of $1.0 million offset in recoveries;
- $0.7 million offset in salaries; and
- Olameter reads of $0.3 million.

iv. The reduction of $1.1 million for consulting is primarily attributable to:

- $0.3 million related to lower than expected outside legal and consulting costs for EB-2011-0210 and EB-2011-0327;
- $0.3 million related to two roles budgeted as consulting but replaced by internal full time positions; and
- $0.5 million related to other miscellaneous variances.

v. The reduction of $1.0 million for affiliate services in 2011 is primarily attributed to:

- $0.7 million of expenses lower than Outlook. This variance consists of the following:
    - a $0.4 million decrease related to forecasted revised Supply Chain structure which was not completed in 2011;
    - a $0.3 million decrease related to a favorable US/Canadian exchange rate;
- $0.3 million of revenue greater than Outlook. This variance consists of the following:
    - a $0.2 million increase in Accounts Payable revenue related to testing and implementation of the new AP system;
    - a $0.1 million increase in Engineering and Construction revenue.

vi. The reduction of $2.7 million for bad debt expense for 2011 is primarily attributed to better than expected collections of past due accounts. By focusing on collections earlier and working out payment arrangements, more accounts have been collected.

b) Three months of actual data were included in the 2011 forecast.

c) $7.0 million of the $11.1 million increase is related to an increase in the 2011 incentive accrual.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, Table 4, Original & Updated

The updated evidence shows an increase in OM&A between 2010 and 2013 of $65.4 million, as compared to the original evidence of $49.3 million. Union's March 27, 2012 cover letter for the updated and corrected evidence indicated that the pension expense had been increased by $18.5 million.

Please explain the following changes in Table 4 between the updated and original evidence:

i) an increase of $19.4 million for benefits (i.e. $0.9 million above the $18.5 million pension increase);
ii) an increase of $2.2 million for Other;
iii) the $4.9 million decrease for Capitalization;
iv) the $0.8 million decrease for Non-Utility & Excess Utility Cross Charge as compared to the original line item of Non-Utility Allocation.

Response:

i) The increase of $19.4 million for benefits can be explained as follows:

Particulars ($ millions)	Defined Benefit Pension	Other Post-retirement Benefits	Total
Experience:			
Experience during 2011	7.4	0.0	7.4
Additional contribution remitted in 2011	(3.0)	0.0	(3.0)
Assumption changes:			
Discount rate	8.1	0.7	8.8
Expected return on assets	3.4	0.0	3.4
Mortality	2.6	0.2	2.8
	18.5	0.9	19.4

ii) On an actual basis vehicle depreciation is expensed as part of gross O&M and then 100% capitalized through direct capitalization. For consistency, the 2013 Forecast was adjusted to reflect the same accounting process. The $2.2 million increase in gross O&M is offset by an increase in direct capitalization. There is no impact to Net O&M.

iii) The $4.9 million is an increase to capitalization. It consists of $2.2 million noted in part ii) above and $2.7 million of capitalization on the $19.4 million of increased benefit costs.

iv) The decrease for non-utility allocation consists of $0.6 million related to the increased pension costs (Exhibit D1, Summary Schedule 2). $0.8 million is derived by comparing D1, Tab 2, Table 4 Updated to the original filing.

Particulars ($ million's)	Updated	Original	Change
Excess Utility Cross Charge	(1.7)		(1.7)
Non-Utility	(6.9)	(7.8)	0.9
Total	(8.6)	(7.8)	(0.8)

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, pages 4 - 9, Updated

a) Please provide the Ontario and Canada CPI for each of 2007 through 2011, along with the most current forecasts available for 2012 and 2013.

b) Please provide the figures, including the 2007 base, used to derive the $17.5 million increase related to inflation. Please show the derivation of 2007 base based on the Board-approved 2007 figures, along with the deductions (shown separately) for DSM, salary and pension/benefit costs.

c) Please update the increase in the total number of general service customers of 110,250 forecast for 2007 to 2013 to reflect actual 2011 data.

d) Please provide a table for 2007 through 2011 actual and the forecasts for 2012 and 2013 that shows the total O&M associated with the regulated utility, the number of customers of the regulated utility and the associated O&M per customer for the regulated utility.

e) Please provide a table for 2007 through 2011 actual and the forecasts for 2012 and 2013 that shows the costs associated with each of the cost drivers shown in lines 6 through 14 in Table 2.

f) Please provide a table for 2007 through 2011 actual and the forecasts for 2012 through 2013 for the number of line locates.

g) Please provide the actual productivity gains for each of 2008 through 2011 in both dollars and percent of OM&A.

h) Please provide a table for 2007 through 2011 actual and the forecasts for 2012 trough 2013 of the percentage capitalized overhead costs of total utility O&M costs.

i) Please provide the yearly percentage figures for 2006 through 2010 that result in the 0.31% noted on page 8 for bad debt.

j) Please provide the yearly figures for the contract bad debt for 2006 through 2010 that range from $0.0 million to $0.6 million noted on page 8.

Response:

a)

Inflation CPI

	Canada		Ontario	
Year	Index	Ann. % ch.	Index	Ann. % ch.
2007	111.5	2.2	110.8	1.8
2008	114.1	2.4	113.3	2.3
2009	114.4	0.3	113.7	0.4
2010	116.5	1.8	116.5	2.5
2011	119.9	2.9	120.1	3.1
2012		2.0		2.0
2013		1.9		2.0

Sources: History – Statistics Canada.
Forecasts: Canada – Consensus Economics March 2012.
Forecasts: Ontario – Average of CIBC, RBC & BMO estimates March 2012.

b) Please see Attachment 1.

c)

	Year	Total	Change
Actual	2007	1,288,836	
Actual	2011	1,359,576	70,740
Forecast	2013	1,399,086	39,510
			110,250

d) Please see Attachment 2.

e) Please see Attachment 3.

f)

Year	Locate Requests
2007 Actual	220,439
2008 Actual	240,399
2009 Actual	258,508
2010 Actual	264,331
2011 Actual	278,540
2012 Forecast	273,627
2013 Forecast	280,929

g) Attachment 4 shows O&M productivity savings in relation to Total Net Utility O&M. Please note that productivity savings also include capital items as outlined in Exhibit A2, Tab 5, Page 2, Table 1, Line 2, Updated which are not included in the calculation.

h) The following table provides the actual for 2007 through 2011 and the forecasts for 2012 through 2013 of the percentage capitalized overhead costs of total gross (net utility costs plus capitalized overheads) utility O&M costs. Overheads are not applied to non utility costs.

Year	Gross Utility O&M ($000's)	Capitalization ($000's)	Capitalized Overhead (%)
2007 Actual	372,567	54,526	15
2008 Actual	383,997	61,266	16
2009 Actual	377,658	59,594	16
2010 Actual	409,641	60,268	15
2011 Actual	436,839	67,369	15
2012 Forecast	451,321	69,808	15
2013 Forecast	463,995	73,028	16

i) The yearly percentage figures for 2006 through 2010 that result in the 0.31% noted on page 8 for bad debt:

2006	2007	2008	2009	2010	Avg
0.32%	0.31%	0.29%	0.35%	0.30%	0.31%

j) The yearly figures for 2006 through 2010 for the actual write-offs in the contract market are:

2006	2007	2008	2009	2010
$568,953	$626,039	$273,016	$530,932	($13,487)

UNION GAS LIMITED
Gross O&M

Line No.	Particulars ($000s)	Board-approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Gross O&M - Total (Line 25 on D1, SS2)	391,907	381,955	396,381	395,078	423,677	452,142	466,787	479,881
2	Salaries/Wages (Line 1 on D1, SS2)	159,896	164,371	172,274	175,066	183,249	191,837	187,950	193,786
3	Benefits (Line 2 on D1, SS2)	55,621	56,365	51,366	52,919	70,861	81,179	82,161	81,083
4	DSM	17,000	17,000	17,000	20,536	22,627	24,890	30,954	31,842
5	Prior Year Gross O&M			381,955	396,381	395,078	423,677	452,142	466,787
6	Less Prior Year Salary & Wages			(164,371)	(172,274)	(175,066)	(183,249)	(191,837)	(187,950)
7	Less Prior Year Pension & Benefits			(56,365)	(51,366)	(52,919)	(70,861)	(81,179)	(82,161)
8	Less Prior Year DSM			(17,000)	(17,000)	(20,536)	(22,627)	(24,890)	(30,954)
9	Base for Calculation			144,220	155,740	146,557	146,940	154,236	165,721
10	Inflation Rate			2.2%	2.4%	0.3%	1.8%	2.9%	2.0%
11	Inflationary Impact			3,173	3,738	440	2,645	4,473	3,314
								Total Inflationary Impact	17,782

Note: 2011 through 2012 have been updated. Amount filed in written evidence was $17.5M based on original filing.

UNION GAS LIMITED
Regulated O&M per Customer

Line No.	Particulars	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Net Utility OM&A ($000's)	318,041	322,731	318,064	349,373	369,470	381,513	390,967
2	# regulated customers	1,289,359	1,309,430	1,325,043	1,343,795	1,360,056	1,379,304	1,399,591
3	OM&A per customer ($'s)	246.67	346.47	240.04	259.99	271.66	276.60	279.34

Union Gas Limited

Summary of O&M Expense Drivers 2007 Board Approved - Forecast 2013

Line 6 - Integrity Management

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
	Pipeline Integrity	no BA	8,290	10,220	6,410	10,040	12,340	14,650	14,730
								Delta from 2007 Actual	**6,440**

Line 7 - ETIC

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
	Energy Technology & Innovation Canada	no BA					1,100	3,400	5,000
								Delta from 2007 Actual	**5,000**

Line 8 - Line Locates

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
	Line Locates	no BA	6,323	6,682	8,148	7,890	9,104	9,617	10,200
								Delta from 2007 Actual	**3,877**

Line 9 - Productivity

Updated

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
25	Gross O&M - Total (line 25 on D1, SS 2)	391,907	381,955	396,381	395,078	423,677	452,142	466,787	479,881
2	Benefits (line 2 on D1, SS 2)	55,621	56,365	51,366	52,919	70,861	81,179	82,161	81,083
	DSM	17,000	17,000	17,000	20,536	22,627	24,890	30,954	31,842
	Cummulative Productivity			2,800	12,500	16,000	15,500		
	Prior Year Gross O&M							452,142	466,787
	Less Prior Year Pension & Benefits							(81,179)	(82,161)
	Less Prior Year DSM							(24,890)	(30,954)
	Less STIP prior year							(25,210)	(15,231)
	Productivity Base							320,863	338,441
	Productivity Factor (1%)							1%	1%
	Total Productivity			2,800	9,700	3,500	(500)	3,209	3,384
								Total Productivity	**22,093**

Note: Amount filed in written evidence was $22.5M as per previous analysis

Line 10 - Capitalization

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
28	Total Capitalization (line 28 on D1, SS 2)	(58,878)	(54,526)	(61,266)	(59,594)	(60,268)	(67,369)	(69,808)	(73,028)
								Delta to 2007 BA	**(14,150)**

Line 11 - Affiliate Services

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
21	Outbound Affiliate Services (line 21 on D1, SS 2)	(5,741)	(6,476)	(7,768)	(9,312)	(10,182)	(11,697)	(13,667)	(13,706)
22	Inbound Affiliate Services (line 22 on D1, SS 2)	11,933	6,303	5,870	7,306	9,462	8,956	11,494	11,888
		6,192	(173)	(1,899)	(2,006)	(720)	(2,741)	(2,173)	(1,818)
								Delta to 2007 BA	**(8,010)**

Line 12 - Non Utility Allocation

Updated

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
30	Non Utility Allocations (line 30 on D1, SS 2)	(6,807)	(7,127)	(10,123)	(12,282)	(11,776)	(13,042)	(13,205)	(13,625)
								Delta to 2007 BA	**(6,818)**

Line 13 - Bad Debt

No.	Particulars ($000s)	2007BA	2007A	2008A	2009A	2010A	2011A	2012F	2013F
23	Bad Debt	11,600	7,300	9,100	8,600	5,075	4,455	6,600	6,600
								Delta from 2007 BA	**(5,000)**

Line 14 - Other

This line represents other small miscellaneous expenses.

Union Gas Limited

O&M Productivity Savings and Net Utility O&M

Line No.	Particulars	2008	2009	2010	2011	Reference
1	Total O&M Cost Savings ($millions)	2.8	12.5	16.0	15.5	Exhibit A2, Tab 5, Page 2, Table 1, Line 1, Updated
2	Incremental O&M Cost Savings ($millions)	2.8	9.7	3.5	(0.5)	
3	Total Net Utility O&M ($millions)	325.0	320.3	351.7	371.7	Exhibit D1, Summary Schedule 2, Line 33, Updated
4	Incremental O&M Cost Saving as % of Total Net Utility O&M	0.9%	3.0%	1.0%	(0.1%)	Line 2 / Line 3

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, page 15, Updated

a) Please provide the total cost of SAP that is to be implemented across Spectra Energy business units.

b) Please provide the total cost of SAP that has been allocated to Union Gas.

c) Please provide the total cost of SAP that has been allocated to the regulated component of Union Gas.

d) Please provide details on how the allocation to Union Gas and the allocation to the regulated component of Union Gas have been done.

Response:

Please see Attachment 1.

a) The total cost of SAP to be implemented across Spectra is $63 million.

b) The total cost allocated to Union annually is $1.7 million.

c) The utility operations are allocated 97% of Union's cost consistent with the allocation of other administrative and general costs.

d) A summary of the modules and basis of allocation is included in Attachment 1. Noted below is a description of the allocators. The allocation factors for each module are noted in the attachment.

   Head Count: Number of FTE's in each BU as a % of total headcount of all BU's

   3 Factor Formula: This is an internal term used by Spectra. It is the same as a commonly used allocator known as the "Massachusetts (Mass) formula". The Mass formula is a method used to allocate costs incurred by a parent company on behalf of its business units. The formula has three parts using the allocation factors of gross property plant and equipment, revenue and labour. The relative percentage of each part as a component of the total of the group is added together and divided by three.

Example: Union's labour as a % of labour of the entire Spectra group of companies is weighted 1/3. The same type of calculation is done for each company and for each of labour, PPE and Revenue. The average % is the Mass allocation factor. Within the attached schedule, there are two versions of the 3 Factor formula. 3 Factor formula –Enterprise is the calculation described above; and 3 Factor –US is the calculation excluding Union and SET-West. This 2nd version of factor distributes costs among BU's within the US and does not result in any allocation to Union or SET-West.

Controller Allocation: A small portion of the Controller function is allocated to Union as part of the Finance SLA. This includes the services for accounting research, internal controls, accounting support, senior management support etc. The allocation factor in the SAP project is the Finance SLA portion of the budget relative to the total controller budget.

Treasury Bank Accounts: Number of banking accounts and treasury deals of each BU relative to the total.

Supply Chain Allocation %: A factor reflecting the relative benefits for enhancing certain SAP modules to support the supply chain function.

The table below is a summary of the allocators.

	Union	SET-West	Spectra
Headcount	41.3%	20.8%	37.9%
3 Factor Enterprise	28.1%	27.0%	44.9%
3 Factor -US	0.0%	0.0%	100.0%
Controller Allocation	12.7%	12.1%	75.1%
Treasury	16.4%	23.7%	59.9%
Supply Chain Excellence	0.2%	1.0%	98.8%

Please see the response to c) above for the allocation to the unregulated business.

Filed: 2012-05-04
EB-2011-0210
J.D-1-2-7
Attachment 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Allocated To				Capex Allocation			
Line #		UGL	SET-West	Spectra	Allocation Factors	UGL	SET-West	Spectra	Total
1	General Accounting	x	x	x	Controller Allocation	$ 1,851	$ 1,764	$ 10,926	$ 14,540
2	Governance and Internal Controls Management	x	x	x	3 factor formula - Enterprise	$ 622	$ 596	$ 993	$ 2,211
3	Travel & Expense Accounting Management	x	x	x	3 factor formula - Enterprise	$ 270	$ 258	$ 430	$ 958
4	Treasury	x	x	x	Treasury Factor	$ 416	$ 600	$ 1,517	$ 2,532
5	HR: Payroll and HRMS	x	x	x	Employee count	$ 9,149	$ 4,611	$ 8,402	$ 22,162
6	Supply Chain	x	x	x	Supply Chain Factor	$ 18	$ 71	$ 7,259	$ 7,348
7	Asset Accounting			x	3 factor formula - US	$ -	$ -	$ 240	$ 240
8	Operations			x	3 factor formula - US	$ -	$ -	$ 5,136	$ 5,136
9	Project Management and Execution			x	3 factor formula - US	$ -	$ -	$ 5,293	$ 5,293
10					**Total**	$ 12,325	$ 7,899	$ 40,195	$ 60,420

11

12 **Table 2 Summary of 2013 SAP Project Charges**

13

Line #		UGL	SET-West	Spectra	Total
14		UGL	SET-West	Spectra	Total
15	CapEx Amortization	$ 1,232	$ 790	$ 1,232	$ 3,255
16	OM Allocation	$ 78	$ 50	$ 256	$ 384
17	SAP Software	$ 393	$ 252	$ 1,282	$ 1,927
18	Total Charge in 2013	$ 1,704	$ 1,092	$ 2,770	$ 5,566

19

20 **Table 3 (Table 2 as a % of Table 2 Totals)**

21

Line #		UGL	SET-West	Spectra	Total
22	**Percent of Total Project**	UGL	SET-West	Spectra	Total
23	Capital	37.9%	24.3%	37.9%	100.0%
24	OM Allocation	20.4%	13.1%	66.5%	100.0%
25	SAP Software	20.4%	13.1%	66.5%	100.0%
26	Average	30.6%	19.6%	49.8%	

UNION GAS LIMITED

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

Ref: Exhibit D1, Summary Schedule 2, Updated

a) Please confirm that the figures provided for 2007 through 2011 are based on CGAAP. If this cannot be confirmed, please indicate which years in the table are based on CGAAP and which are based on USGAAP.

b) Please provide a version of Summary Schedule 2 that includes actual data for 2011 but also uses CGAAP to forecast the 2012 and 2013 costs associated with benefits and any other costs that are different between USGAAP and CGAAP.

Response:

a) Confirmed. The figures provided for 2007 through 2011 are based on CGAAP.

b) The 2011 actual and 2012 forecast information provided in Exhibit D1, Summary Schedule 2 Updated are based on CGAAP. Attachment 1 provides the 2013 forecast based on CGAAP. Benefits is the only item impacted as a result of moving from CGAAP to USGAAP.

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31

Line No.	Particulars ($000s)	Board Approved 2007	Actual 2007	Actual 2008	Actual 2009 [2]	Actual 2010	Actual 2011 [4]	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Salaries/Wages	159,896.0	164,371.2	172,274.5	175,065.7	183,249.1	191,836.8	187,950.4	193,786.4
2	Benefits	55,621.0	56,364.5	51,366.1	52,919.0	70,861.2	81,178.8	82,161.4	85,768.7
3	Materials	9,132.0	9,973.0	10,696.2	10,692.9	9,631.1	10,700.6	9,241.6	9,957.8
4	Employee Expenses/Training	12,798.0	12,033.7	13,714.4	10,887.9	11,783.4	13,513.6	14,109.8	14,330.2
5	Contract Services	50,061.0	51,194.0	55,317.4	56,107.4	57,335.1	63,607.6	63,669.5	66,376.2
6	Consulting	6,447.0	7,277.0	8,269.5	6,689.0	7,505.6	7,712.8	11,082.3	13,171.6
7	General	20,645.0	18,031.9	21,837.4	19,939.7	21,210.7	22,261.9	21,592.3	22,189.8
8	Transportation and Maintenance	7,523.0	7,317.5	8,159.3	7,645.4	7,891.8	9,011.8	9,374.4	9,760.9
9	Company Used Gas	4,911.0	3,167.4	3,547.5	3,373.3	2,451.1	2,400.6	2,473.4	2,501.6
10	Utility Costs	3,269.0	3,315.6	3,533.9	3,236.0	3,704.2	4,069.2	4,561.9	4,681.9
11	Communications	7,969.0	7,980.8	8,224.6	7,599.9	6,780.3	6,394.1	6,243.2	6,380.1
12	Demand Side Management Programs	11,874.0	11,569.1	12,471.3	14,391.3	16,437.6	17,925.3	23,605.1	24,231.9
13	Advertising	2,255.0	2,117.7	1,543.9	1,568.9	1,860.4	2,376.2	2,287.7	2,385.9
14	Insurance	7,004.0	8,029.9	7,240.1	7,763.3	8,506.8	8,100.8	8,605.1	9,056.0
15	Donations	404.0	377.2	451.0	500.8	749.1	631.8	774.6	787.6
16	Financial	2,884.0	1,661.3	2,117.0	2,917.6	2,077.1	1,681.5	1,860.4	1,871.0
17	Lease	3,202.0	3,381.5	3,198.1	3,479.5	3,632.3	4,091.6	4,151.1	4,191.0
18	Cost Recovery from Third Parties	(2,106.0)	(3,288.8)	(3,770.3)	(5,362.7)	(4,641.2)	(5,869.3)	(2,882.9)	(2,549.1)
19	Computers	4,226.0	4,101.6	4,263.1	4,678.2	4,922.1	5,286.6	6,158.1	6,464.7
20	Regulatory Hearing & OEB Cost Assessment	6,000.0	5,751.8	4,487.9	3,652.6	3,126.1	3,305.8	5,200.0	4,300.0
21	Outbound Affiliate Services	(5,741.0)	(6,475.9)	(7,768.4)	(9,312.3)	(10,182.2)	(11,697.2)	(13,667.2)	(13,706.2)
22	Inbound Affiliate Services	11,933.0	6,302.5	5,869.9	7,306.2	9,462.2	8,956.1	11,494.4	11,888.2
23	Bad Debt	11,600.0	7,300.0	9,100.0	8,600.0	5,075.3	4,455.1	6,600.0	6,600.0
24	Other	100.0	100.8	236.5	738.6	248.2	209.8	140.4	141.0
25	Total	391,907.0	381,955.3	396,380.9	395,078.2	423,677.4	452,141.9	466,787.0	484,567.2
26	Indirect Capitalization (OH)	(51,528.0)	(47,275.2)	(52,675.2)	(51,246.2)	(46,289.6)	(52,220.0)	(50,789.0)	(52,032.0)
27	Direct Captialization (DCC)	(7,350.0)	(7,250.7)	(8,590.4)	(8,348.0)	(13,978.3)	(15,149.0)	(19,019.1)	(21,651.6)
28	Total Capitalization	(58,878.0)	(54,525.9)	(61,265.6)	(59,594.2)	(60,267.9)	(67,369.0)	(69,808.1)	(73,683.6)
29	Total	333,029.0	327,429.4	335,115.3	335,484.0	363,409.5	384,772.9	396,978.9	410,883.6
30	Non Utility Allocations [1]	(6,807.0)	(7,127.0)	(10,122.8)	(12,282.2)	(11,775.9)	(13,041.9)	(13,204.7)	(13,765.9)
31	IFRS Costs	-	-	-	(2,877.0)	-	-	-	-
33	Total Net Utility Operating and Maintenance Expense	326,222.0	320,302.4	324,992.5	320,324.8	351,633.6	371,731.0	383,774.2	397,117.7
34	Excess Utility Cross-Charge [3]	(599.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)
35	Total Net Utility O&M Less Cross-Charge	325,623.0	318,041.4	322,731.5	318,063.8	349,372.6	369,470.0	381,513.2	394,856.7

Note:
(1) Includes charitable donations and prior period PST assessment.
(2) 2009 Actuals do not include $9M related to Lobo C and St. Clair.
(3) 2013 Utility Cross-Charge is an estimate and will be updated as part of the cost study.
(4) 2011 Actuals do not include $6M reduction related to St. Clair.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 3, Schedule 2, Updated

a) Do the donations shown on line 15 of the table on page 1 include LEAP funding? If yes, please provide the amount of the LEAP funding and a breakdown of any remaining components of the donations. If no, please provide a breakdown of the donations expenses and indicate where and the amount of any LEAP funding has been included in costs.

b) Please explain the reduction in Cost Recovery from Third Parties in 2013 relative to 2012 shown in line 18 of the table on page 1.

c) Please explain the reduction in forecasted costs in 2013 relative to 2012 for Regulatory Hearing & OEB Cost Assessment shown on line 20 of the table on page 1 and the "rebasing" explanation provided on page 7.

d) Please provide a breakdown of the forecast cost of this proceeding between the various components (legal, consulting, intervenors, OEB, etc.). Has Union included all of these costs in the 2013 revenue requirement or have the costs been amortized over a longer period? Please provide details.

e) Please provide the actual OEB cost assessment for each of 2007 through 2011 and the forecast for 2012 and 2013.

Response:

a) The donations shown on line 15 of the table on page 1 do not include LEAP funding. Financial assistance for Low-income gas customers in Union's franchise area is currently funded through the Winter Warmth Program rather than a LEAP program. The Winter Warmth funds are provided exclusively from the late-payment class action settlement. No other funds from non-distributor sources (i.e., donations) contribute to the Winter Warmth program.

   OEB correspondence on October 20, 2010 in EB-2008-0150/EB-2007-0722/EB-2008-0346 stated that the OEB expects Enbridge and Union will ensure that the funding available for emergency financial assistance in 2011 will be the equivalent of at least 0.12% of total distribution revenue. Union does not require a LEAP program yet since it is expected the

Winter Warmth fund will continue to have sufficient funds equivalent of at least 0.12% of total distribution revenue for the 2013 year.

Donations are a non-utility cost that is not budgeted at a program level. Therefore, a breakdown of donations is not available.

b) There is $0.381 million in the 2012 forecast related to HR project costs that will be recovered in 2012.

c) The 2012 budget related to Regulatory Hearing and OEB costs was increased in 2012 to reflect anticipated higher costs associated with the 2013 rebasing proceeding. The 2013 budget was reduced as a result of the rebasing proceeding being completed in 2012. The reduction of $900,000 consists of a reduction of $700,000 in budgeted intervenor costs and a reduction of $200,000 in anticipated OEB cost assessment between 2012 and 2013.

d) The 2012 and 2013 Regulatory budget was not prepared by individual proceeding. The costs associated with the 2013 rebasing proceeding were budgeted to be incurred in 2012 and are not amortized over a longer period.

e) OEB Costs Assessments are as follows:

	Actual	Forecast
2007	3,454,854.00	-
2008	2,511,016.11	-
2009	2,652,276.00	-
2010	2,539,738.00	-
2011	2,460,049.00	-
2012	-	3,000,000.00
2013	-	2,800,000.00

UNION GAS LIMITED

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

Ref: Exhibit D5, Tab 1, Schedule 1

a) Please explain what the negative Other expense of $709 shown for 2011 is related to.

b) Has Union had negative Other expenses in 2007 through 2010? If yes, please provide details.

Response:

a) The negative Other expense of $709 shown for 2011 is comprised of a gain on foreign exchange of $674 and a gain on sale of assets of $35.

b) Union has not had net utility negative Other expenses in the years 2007 through 2010.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 3, Schedule 2, Updated

What is the impact on the forecast cost for Employment Insurance premiums as a result of the March 29, 2012 federal budget that limits the increase in premiums to no more than 5 cents per year?

Response:

There is no impact since Union assumed the premium increase from 2011 to 2013 was 5 cents per year based on historical trending.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 2, Page 5 Customer Growth

a) Please update the 2007 Cost Study $110 for customer adds. Why is this still valid?

b) Customer Charge covers what costs? Please provide a breakdown.

c) Please provide Costs vs Customer Charge revenue 2007-2013.

Response:

a) The $110 per customer cost from the 2007 Board-approved cost allocation study was used to forecast the 2013 costs associated with customer growth because at the time that the 2013 forecast was being prepared that was the best available information. Based on Union's Updated 2013 cost allocation study, the 2013 annual variable O&M cost Union incurs when new customers are attached to Union's system is approximately $116 per customer. Please see Attachment 1 for the calculation of the distribution O&M per customer.

b) The customer charge is intended to recover a portion of Union's customer-related costs. Please see the response at Exhibit J.H-4-4-1 a) for Union's definition of customer-related costs.

c) A summary of the 2007-2013 customer-related costs and monthly charge revenue for General Service rate classes Rate 01, Rate 10, Rate M1, and Rate M2 is provided at Attachment 2.

UNION GAS LIMITED

Distribution O&M Per Customer Based on 2013 Cost Study filed March 27th, 2012

Line No.	Particulars ($000s)	General Service[1] Distribution Customer	General Service[1] Distribution Demand	Total
		(a)	(b)	(c = a + b)
	O&M Expense			
1	Distribution	40,908	13,002	53,909
2	General Operating & Engineering	15,621	5,213	20,834
3	Sales Promotion & Merchandise	8,786	19,387	28,172
4	Distribution Customer Accounting	53,106	0	53,106
5	Distribution-Related Employee Benefits	3,524	687	4,212
6	Total Distribution-Related O&M Costs[2]	121,945	38,289	160,234
7	Average Number of Customers	1,387,142	1,387,142	1,387,142
8	Per Customer Distribution Related O&M Expense (line 6 / line 7 x 1000)	88	28	116

Notes:

1 Distribution-related costs allocated to general service rate classes, including M1, M2, R01 and R10.

2 Distribution-related O&M expense excludes administrative and general operating expenses.

UNION GAS LIMITED
Summary of Customer-Related Costs and Monthly Customer Charge Revenue
for General Service Rate Classes for the period 2007-2013

Line No.	Particulars ($000's)		Rate 01	Rate 10	Rate M1	Rate M2
			(a)	(b)	(c)	(d)
1	2007 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
2	(EB-2005-0520)	Monthly Charge Revenue	56,769	2,488	188,176	5,862
3		Percent Recovery	57.3%	46.9%	76.6%	83.9%
4	2008 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
5	(EB-2007-0606)	Monthly Charge Revenue	60,317	2,488	199,937	5,862
6		Percent Recovery	60.8%	46.9%	81.4%	83.9%
7	2009 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
8	(EB-2008-0220)	Monthly Charge Revenue	63,865	2,488	211,698	5,862
9		Percent Recovery	64.4%	46.9%	86.2%	83.9%
10	2010 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
11	(EB-2009-0275)	Monthly Charge Revenue	67,413	2,488	223,459	5,862
12		Percent Recovery	68.0%	46.9%	91.0%	83.9%
13	2011 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
14	(EB-2010-0148)	Monthly Charge Revenue	70,961	2,488	235,220	5,862
15		Percent Recovery	71.6%	46.9%	95.8%	83.9%
16	2012 Approved	Customer-Related Costs	99,129	5,301	245,566	6,985
17	(EB-2011-0025)	Monthly Charge Revenue	74,509	2,488	246,981	5,862
18		Percent Recovery	75.2%	46.9%	100%	83.9%
19	2013 Proposed	Customer-Related Costs	117,795	3,770	282,101	8,992
20	(EB-2011-0210)	Monthly Charge Revenue	80,490	1,720	266,843	5,702
21		Percent Recovery	68.3%	45.6%	94.6%	63.4%

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 2, Page 8

Union's costs allocated to the non-utility business in 2013 are forecast to increase to $6.9 million (was $7.8 million) over the 2007 Board-approved amount. Annually, cost groups are reviewed to ensure an appropriate allocation between regulated and unregulated work. The 2013 forecast assumes $2.3 million for the excess utility space cross charge. The cross charge will be updated in the phase II evidence.

If O&M costs have increased for 2013 by almost $20 million since filing, please explain why the Non- utility allocation has *decreased* by $1million?

Response:

The total non-utility allocation including the excess utility cross charge increased from $7.8 million to $8.6 million. In the updated evidence, the excess utility cross-charge change of $1.7 million was broken out into a separate line. Please see Exhibit D1, Tab 2, Table 4, Lines 20 and 21.

UNION GAS LIMITED

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

Ref: A2 T3 S1 page 5

For each year 2007-2013 inclusive, please provide (i) the internally approved O&M budget and (ii) a list of any differences between the O&M budgets submitted for Senior Management Review and Approval and the final O&M budget approved.

Response:

Please see Attachments 1-4.

A list of differences between the O&M budgets submitted for Senior Management Review and Approval for the years 2007 to 2009 are not available.

UNION GAS LIMITED
2010 Budget Iterations

Line No.	($ million's)	(a)	Net O&M (b)	Non Utility Allocation (c)	Excess Utility Cross Charge (d)	Net Utility O&M (e)
1	June 5, 2009 budget		449.5	(11.2)	(2.3)	436.0
	Subsequent changes					
2	Affiliate revenue/expense	0.2				
3	Foreign exchange	(1.1)				
4	Salary & wages (merit increase)	0.6				
5	SMC Filters	(0.4)	(0.7)			
6	August 14, 2009 budget		448.8	(11.2)	(2.3)	435.3
	Subsequent changes					
7	Affiliate revenue/expense	1.0				
8	Capitalization impacts	(1.6)				
9	General & other	(0.8)				
10	Insurance	1.0				
11	Pension benefits	6.6				
12	Salary & wages	0.9	7.1			
13	August 28, 2009 budget		455.9	(11.5)	(2.3)	442.1
	Subsequent changes					
14	Green Energy Act costs	(95.0)	(95.0)			
15	February 2009, budget		360.9	(11.5)	(2.3)	347.1

UNION GAS LIMITED
2011 Budget Iterations

Line No.	($ million's)	(a)	Net O&M (b)	Non Utility Allocation (c)	Excess Utility Cross Charge (d)	Net Utility O&M (e)
1	July 26, 2010 budget		376.9	(11.9)	(2.3)	362.7
	Subsequent changes					
2	Affiliate Revenue/Expense	3.4				
3	Capitalization Impacts	(0.5)				
4	Consulting	(1.4)				
5	Cross Bore	(2.3)				
6	Employee expenses & training	(0.4)				
7	Financial costs	(0.3)				
8	Meter Barricades	(0.8)				
9	Other	(0.6)				
10	Pension benefits	3.3				
11	Salaries & wages (promotional increase & other)	(0.7)				
12	Transportation	(0.2)	(0.5)			
13	August 30, 2010 budget		376.4	(11.9)	(2.3)	362.2
	Subsequent changes					
14	Bad Debt	(0.3)				
15	Consulting - CIS replacement	(0.3)				
16	Consulting - Market Development	(1.1)				
17	Employee expenses & training	(1.1)				
18	Lease costs	(0.6)				
19	Line locates	(0.7)				
20	Other	(0.2)	(4.3)			
21	September 16, 2010 budget		372.1	(11.8)	(2.3)	358.0
	Subsequent changes					
22	Foreign Exchange reductions	(0.6)	(0.6)			
23	October 12, 2010 budget		371.5	(11.8)	(2.3)	357.4

UNION GAS LIMITED
2012 Budget Iterations

Line No.	($ million's)	(a)	Net O&M (b)	Non Utility Allocation (c)	Excess Utility Cross Charge (d)	Net Utility O&M (e)
1	July 4, 2011 budget		387.4	(13.0)	(2.3)	372.1
	Subsequent changes					
2	Affiliate Revenue/Expense	(0.8)				
3	Bad Debt	(0.5)				
4	Capitalization correction	1.0				
5	Communications	(0.3)				
6	Consulting	(0.4)				
7	Contract Services	(1.8)				
8	Dow Moore JV	(0.3)				
9	Employee Expenses	(0.4)				
10	Financial costs	(0.1)				
11	Insurance	(0.8)				
12	Intervenor costs	(0.3)				
13	Materials	(0.5)				
14	Non Pension Benefits	(0.8)				
15	OEB Assessment	(0.2)				
16	Other	(0.4)				
17	Payroll costs	(0.5)				
18	Pension Benefits (CDN GAAP amortization)	4.4				
19	Salaries and wages (merit & other)	(2.4)				
20	Transportation	(0.2)	(5.2)			
21	August 15, 2011 budget		382.2	(12.8)	(2.3)	367.1
	Subsequent changes					
22	Community Investment	0.4				
23	DSM Proceeding	5.7				
24	Other	0.4	6.5			
25	September 20, 2011 (November 2011 evidence)		388.7	(12.8)	(2.3)	373.6
	Subsequent changes					
26	Increased pension costs	9.9				
27	Capitalization on increased pension costs	(1.6)	8.3			
28	March 2012 evidence		397.0	(13.2)	(2.3)	381.5

UNION GAS LIMITED
2013 Budget Iterations

Line No.	($ million's)	(a)	Net O&M (b)	Non Utility Allocation (c)	Excess Utility Cross Charge (d)	Net Utility O&M (e)
1	July 4, 2011 budget		389.5	(13.1)	(2.3)	374.1
	Subsequent changes					
2	Affiliate Revenue/Expense	(0.1)				
3	Bad Debt	(0.5)				
4	Benefits	(1.1)				
5	Communications	(0.3)				
6	Dow Moore Joint Venture	(0.3)				
7	Employee Expense	(0.3)				
8	Insurance	(0.6)				
9	Salaries and wages (merit & other)	(4.0)				
10	Other	(0.2)				
11	Postage	(0.1)				
12	Regulatory	(0.2)				
13	Capitalization	1.1				
14	Tranportation	(0.2)	(6.8)			
15	August 15, 2011 budget		382.7	(13.0)	(2.3)	367.4
	Subsequent changes					
16	DSM	7.0				
17	Other	0.2				
18	Salaries and wages	0.3	7.5			
19	September 20, 2011 (November 2011 evidence)		390.2	(13.0)	(2.3)	374.9
	Subsequent changes					
20	Increased pension costs	19.4				
21	Capitalizaton on increased pension costs	(2.7)	16.7			
22	March 2012 evidence		406.9	(13.6)	(2.3)	391.0

UNION GAS LIMITED

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

Ref: D1, SS2 Updated, line 2 and Exhibit D1, Tab 3

The referenced exhibit shows an increase in benefits costs of almost $20M in 2013. Also, 2011 and 2012 costs show large increases over 2010 and 2010 costs show a huge increase over 2009.

a) How many of Union`s employees have a defined benefits pension plan?

b) How many of Union`s employees have a defined contributions pension plan?

c) Among Union's cohorts for comparative compensation purposes, how many and what percentage have defined benefits pension plans?

d) Has Union considered moving towards a defined contribution pension plan for all employees?

e) The Updated exhibit shows an increase of almost $20M extra for 2013 over the originally forecasted 2013. Please explain why the cost of benefits has increased so much since the originally filed exhibit.

Response:

a) Please see the response at Exhibit J.D-9-2-2.

b) Please see the response at Exhibit J.D-9-2-2.

c) DB pension plans remain the predominant plan design among Spectra Energy/Union Gas' peer group. Specifically, in the most recently completed review by Towers Watson, 13 of 20 (65%) of the organizations in Spectra Energy/Union Gas' peer group continue to provide a DB pension plan option.

d) Union provides a competitive pension plan offering to help ensure it can attract and retain the talent it needs to operate the business. As noted in the response to part c) above, the DB plan continues to be the predominant pension plan design among the Spectra Energy/Union Gas peer group. Union, however, continues to offer both a DB and a DC pension plan in order to appeal to a diverse range of potential new employees in terms of age and career expectations.

e) Please see the response at Exhibit J.D-1-2-5 i).

UNION GAS LIMITED

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

Ref: A2 T1 S1 page 27

a) Absent the LTIP, does Union expect it would lose the key leadership employees who enjoy this benefit?

b) Please provide a list of positions which received the LTIP for each year 2007-2013 inclusive.

Response:

a) LTIP is an important component of the total compensation opportunity provided to key leadership employees. The existence of an LTIP component within reward packages is common in the marketplace where Union competes for talent for key leadership level roles. It aids in the retention of key executive and leadership talent. Without an LTIP plan, Union would need to increase base salary or STIP levels to achieve total compensation competitiveness in the labour market and retain existing employees. Also, without an LTIP plan, Union would lose the focus on long-term growth from its senior management group.

b) There are 31 roles at Union who are eligible for LTIP awards. These roles include the President, all Vice-Presidents, and certain Director roles. The roles that are identified as eligible for LTIP are based on their ability to contribute to the long-term growth of the company, and based on market data.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit A2, Tab 3, Schedule 1, page 5

The evidence states with respect to the budget process the budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. For the 2013 budget please identify any major changes made by senior management through that process, and explain why those changes were made.

Response:

Please see the response at Exhibit J.D-1-4-1 for changes made by senior management throughout the budget process. Major changes include: 1) salary and wage decrease related to the change in salary and wage assumptions as identified in Exhibit A2, Tab 3, Schedule 1, Appendix A and Exhibit A2, Tab 3, Schedule 1, Appendix B; 2) DSM cost increase as a result of the DSM proceeding and 3) increased pension costs as a result of a Towers Watson update.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2

Please provide a schedule setting out O&M per customer for the years 2007-2013.

Response:

Please see the response at Exhibit J.D-1-2-6 d).

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 12

Contract Services are increasing by $2.7 million in 2013 relative to 2012. Contract Services are increasing in 2012 by $2.9 million relative to 2011. Please provide an explanation as to what items are included in Contract Services and a budget for each item for the years 2007-2013. Please explain how these amounts are forecast.

Response:

Please see Attachment 1.

The starting point for the Contract Services budget is generally the prior year's actuals which are then adjusted for inflation. New projects/initiatives that are known at the time of the forecast are added and projects/initiatives completed in the prior year that are not expected to continue are subtracted.

UNION GAS LIMITED
Contract Services 2007 - 2013

Line No.	Particulars ($)	Board Filed 2007	Budget 2008	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Service Contractors	52,244,968	50,945,979	52,253,677	61,518,175	59,458,621	62,942,603	65,634,652
2	Restoration and Excavation	139,265	3,527,106	1,990,897	800,711	544,713	715,863	730,405
3	Field Surveying	-	30,000	17,143	-	-	-	-
4	Radiography	-	191,500	172,214	6,617	6,000	10,992	11,184
5	Ultrasonics	-	77,000	73,428	2,036	-	-	-
6	Total	52,384,233	54,771,585	54,507,359	62,327,538	60,009,334	63,669,458	66,376,241

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 12-13

Consulting Services are increasing by $2.1 million in 2013 and by $2.3 million in 2012. Please provide an explanation as to what items are included in Consulting Services and a budget for each item for the years 2007-2013. Please explain how these amounts are forecast.

Response:

Please see Attachment 1.

The starting point for the Consulting Services budget is generally the prior year's actuals which are then adjusted for inflation. New projects/initiatives that are known at the time of the forecast are added and projects/initiatives completed in the prior year that are not expected to continue are subtracted.

UNION GAS LIMITED
Consulting Expenses 2007 - 2013

Line No.	Particulars ($)	Board Filed 2007	Budget 2008	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Consulting Fee	6,005,540	6,514,630	6,608,228	7,159,501	6,761,761	8,916,128	11,045,320
2	Recruitment Agency	91,912	191,288	157,275	136,938	99,192	167,239	169,357
3	IFRS Consulting Fee	-	-	1,002,000	378,231	-	-	-
4	Inspectors	-	280,000	160,000	-	429,000	479,000	579,000
5	Environmental	-	12,000	8,572	-	-	4,524	4,620
6	Outside Legal Counsel	1,375,000	1,542,297	1,394,178	1,399,978	1,500,658	1,515,424	1,373,273
7	Total	7,472,452	8,540,215	9,330,253	9,074,648	8,790,611	11,082,315	13,171,570

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 15

During the period 2007-2010 there were reductions in affiliate services and the associated costs of those services. Please explain what services were reduced and the associated costs. Have those reductions continued in the period 2011-2013. If not, why not? If so, please identify those items where the associated costs have been reduced.

Response:

Please see Attachment 1 for the differences between Board-approved 2007 and Actual 2010 by service type. Please see Exhibit D1, Tab 7, Updated, p. 5 for additional information. The change over the period 2007-2010 is not a trend that can be expected to recur in subsequent periods. The forecast for 2013 in Exhibit D1, Tab 7, Schedules 1, 2 and 3 is Union's best estimate at this time.

UNION GAS LIMITED
Affiliate Revenue/Expense
($000's)

		Affiliate Revenue			Affiliate Expense			Net Affiliate Revenue (Expense)		
Line No.	Functional Service	2007 Board-Approved	2010 Actual	Variance	2007 Board-Approved	2010 Actual	Variance	2007 Board-Approved	2010 Actual	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Audit	568	206	(361)	36	708	672	532	(501)	(1,033)
2	Bus Devel, S&T	197	377	180	336	308	(28)	(139)	69	208
3	Corp Services		36	36	367	77	(290)	(367)	(42)	326
4	Engineering & Contruction	45	1,177	1,132	2,810	513	(2,297)	(2,765)	664	3,429
5	EHS	282	705	423	382	538	156	(100)	167	267
6	Ethics	-	-	-		188	188	-	(188)	(188)
7	Finance	760	1,046	287	1,338	1,202	(136)	(579)	(156)	423
8	HR	789	2,174	1,385	3,021	2,281	(740)	(2,232)	(107)	2,125
9	Insurance	10	116	106	1,309	92	(1,217)	(1,299)	23	1,323
10	IT	2,044	2,906	862	1,451	1,985	534	593	921	328
11	Legal		9	9	470	129	(341)	(470)	(120)	350
12	Other	159	38	(121)	(241)	-	241	400	38	(362)
13	Public Affairs	-	-	-	125	25	(100)	(125)	(25)	100
14	Supply Chain	54	471	417	490	703	213	(436)	(232)	203
15	Tax	833	921	88	39	338	299	795	583	(211)
16	Sub Total	5,741	10,182	4,441	11,933	9,087	(2,846)	(6,192)	1,095	7,287
17	Depreciation					375	375	-	(375)	(375)
18	Total	5,741	10,182	4,441	11,933	9,462	(2,471)	(6,192)	720	6,912
19	OH Capitalization	-	3	3		1,674	1,674	-	(1,671)	(1,671)
20	Unregulated Allocation		256	256		218	218	-	38	38
21	Net Regulated	5,741	9,923	4,182	11,933	7,570	(4,362)	(6,192)	2,353	8,544

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2

Please provide a detailed schedule setting out Regulatory Costs for the years 2007-2013. Please set out all of the individual items including Legal, Consulting, Intervenor, OEB, etc.

Response:

Please see the response at Exhibit J.D-1-5-8 and note the following cost type items:

- Consulting – Regulatory
- Outside Legal Counsel – Regulatory
- OEB Cost Assessment Charges
- Intervenor Costs
- OEB Cost Assessment (for Budget data)

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D3, Tab 3, Schedule 2

Please reproduce "Operating and Maintenance by Cost Type" to include 2007 Board Approved, and actuals for the period 2007-2011.

Response:

Please see Attachments 1-4.

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars ($000s)	Actual 2007	Board-Approved 2007	Difference	%
		(a)	(b)	(c)	(d)
1	Salaries/Wages	164,371	159,896	4,475	2.80%
2	Benefits	56,364	55,621	743	1.34%
3	Materials	9,973	9,132	841	9.21%
4	Employee Expenses/Training	12,034	12,798	(764)	(5.97%)
5	Contract Services	51,194	50,061	1,133	2.26%
6	Consulting	7,277	6,447	830	12.87%
7	General	18,032	20,645	(2,613)	(12.66%)
8	Transportation and Maintenance	7,317	7,523	(206)	(2.73%)
9	Company Used Gas	3,167	4,911	(1,744)	(35.50%)
10	Utility Costs	3,316	3,269	47	1.43%
11	Communications	7,981	7,969	12	0.15%
12	Demand Side Management Programs	11,569	11,874	(305)	(2.57%)
13	Advertising	2,118	2,255	(137)	(6.09%)
14	Insurance	8,030	7,004	1,026	14.65%
15	Donations	377	404	(27)	(6.63%)
16	Financial	1,661	2,884	(1,223)	(42.40%)
17	Lease	3,381	3,202	179	5.60%
18	Cost Recovery from Third Parties	(3,289)	(2,106)	(1,183)	56.16%
19	Computers	4,102	4,226	(124)	(2.94%)
20	Regulatory Hearing & OEB Cost Assessment	5,752	6,000	(248)	(4.14%)
21	Outbound Affiliate Services	(6,476)	(5,741)	(735)	12.80%
22	Inbound Affiliate Services	6,303	11,933	(5,630)	(47.18%)
23	Bad Debt	7,300	11,600	(4,300)	(37.07%)
24	Other	101	100	1	0.75%
25	Total Gross Operating and Maintenance Expense	381,955	391,907	(9,952)	(2.54%)
26	Indirect Capitalization	(47,275)	(51,528)	4,253	(8.25%)
27	Direct Capitalization	(7,251)	(7,350)	99	(1.35%)
28	Total Utility Operating and Maintenance Expense	327,429	333,029	(5,600)	(1.68%)
29	Non-Utility Allocations	(7,127)	(6,807)	(320)	4.70%
30	Total Net Utility Operating and Maintenance Expense	320,302	326,222	(5,920)	(1.81%)
31	Excess Utility Cross-Charge Surcharge	(2,261)	(599)	(1,662)	277.46%
32	Total Net Utility O&M Less Cross-Charge Surcharge	318,041	325,623	(7,582)	(2.33%)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Salaries / Wages	
1	2007 Actual	164,371
2	2007 Board-Approved	159,896
3	Difference	4,475
	Reasons:	
4	Incentive accrual/payout	7,990
5	Pay Equity adjustment	(993)
6	GDAR roles not required	(400)
7	Additional resources allocated to capital work	(299)
8	Other	(1,823)
9	Total difference: 2007 Actual vs. 2007 Board-Approved	4,475
	Benefits	
10	2007 Actual	56,364
11	2007 Board-Approved	55,621
12	Difference	743
	Reasons:	
13	Non pension benefit costs higher than plan	1,528
14	Pension benefit costs lower than plan	(760)
15	Other	(25)
16	Total difference: 2007 Actual vs. 2007 Board-Approved	743
	Materials	
17	2007 Actual	9,973
18	2007 Board-Approved	9,132
19	Difference	841
	Reasons:	
20	Purchase of 400 new docking stations	326
21	Other	515
22	Total difference: 2007 Actual vs. 2007 Board-Approved	841

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Employee Expenses / Training	
1	2007 Actual	12,034
2	2007 Board-Approved	12,798
3	Difference	(764)
	Reasons:	
4	Moving expenses	(234)
5	Training expenses	(649)
6	Other	119
7	Total difference: 2007 Actual vs. 2007 Board-Approved	(764)
	Contract Services	
8	2007 Actual	51,194
9	2007 Board-Approved	50,061
10	Difference	1,133
	Reasons:	
11	Project work offset in recovery	964
12	Increased maintenance/integrity spend	469
13	Payroll system change delayed until 2008	(636)
14	Other	336
15	Total difference: 2007 Actual vs. 2007 Board-Approved	1,133
	Consulting	
16	2007 Actual	7,277
17	2007 Board-Approved	6,447
18	Difference	830
	Reasons:	
19	NGEIR & IFRS Consulting	568
20	Other	262
21	Total difference: 2007 Actual vs. 2007 Board-Approved	830
	General	
22	2007 Actual	18,032
23	2007 Board-Approved	20,645
24	Difference	(2,613)
	Reasons:	
25	Increased maintenance/integrity spend	721
26	Dow storage pool commodity toll	(646)
27	Cushion Gas OEB decision	(3,253)
28	Other	565
29	Total difference: 2007 Actual vs. 2007 Board-Approved	(2,613)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Transportation and Maintenance	
1	2007 Actual	7,317
2	2007 Board-Approved	7,523
3	Difference	(206)
	Reasons:	
4	Newer fleet resulted in lower maintenance and repair	(200)
5	Other	(6)
6	Total difference: 2007 Actual vs. 2007 Board-Approved	(206)
	Company Used Gas	
7	2007 Actual	3,167
8	2007 Board-Approved	4,911
9	Difference	(1,744)
	Reasons:	
10	Volume adjustment	(660)
11	Lower volume usage	(649)
12	Lower natural gas prices	(431)
13	Other	(4)
14	Total difference: 2007 Actual vs. 2007 Board-Approved	(1,744)
	Utility Costs	
15	2007 Actual	3,316
16	2007 Board-Approved	3,269
17	Difference	47
	Reasons:	
18	Increased hydro costs	47
19	Total difference: 2007 Actual vs. 2007 Board-Approved	47
	Communications	
20	2007 Actual	7,981
21	2007 Board-Approved	7,969
22	Difference	12
	Reasons:	
23	Other	12
24	Total difference: 2007 Actual vs. 2007 Board-Approved	12

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Demand Side Management Programs	
1	2007 Actual	11,569
2	2007 Board-Approved	11,874
3	Difference	(305)
	Reasons:	
4	Other	(305)
5	Total difference: 2007 Actual vs. 2007 Board-Approved	(305)
	Advertising	
6	2007 Actual	2,118
7	2007 Board-Approved	2,255
8	Difference	(137)
	Reasons:	
9	Other	(137)
10	Total difference: 2007 Actual vs. 2007 Board-Approved	(137)
	Insurance	
11	2007 Actual	8,030
12	2007 Board-Approved	7,004
13	Difference	1,026
	Reasons:	
14	Increased insurance premiums	1,026
15	Total difference: 2007 Actual vs. 2007 Board-Approved	1,026
	Donations	
16	2007 Actual	377
17	2007 Board-Approved	404
18	Difference	(27)
	Reasons:	
19	Other	(27)
20	Total difference: 2007 Actual vs. 2007 Board-Approved	(27)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Financial	
1	2007 Actual	1,661
2	2007 Board-Approved	2,884
3	Difference	(1,223)
	Reasons:	
4	Audit fee	(1,012)
5	Lower bad debt collection fees	(206)
6	Other	(5)
7	Total difference: 2007 Actual vs. 2007 Board-Approved	(1,223)
	Lease	
8	2007 Actual	3,381
9	2007 Board-Approved	3,202
10	Difference	179
	Reasons:	
11	Other	179
12	Total difference: 2007 Actual vs. 2007 Board-Approved	179
	Cost Recovery from Third Parties	
13	2007 Actual	(3,289)
14	2007 Board-Approved	(2,106)
15	Difference	(1,183)
	Reasons:	
16	Higher level of cost recovery	(1,181)
17	Other	(2)
18	Total difference: 2007 Actual vs. 2007 Board-Approved	(1,183)
	Computers	
19	2007 Actual	4,102
20	2007 Board-Approved	4,226
21	Difference	(124)
	Reasons:	
22	Other	(124)
23	Total difference: 2007 Actual vs. 2007 Board-Approved	(124)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2007 Actual vs. 2007 Board-Approved

Line No.	Particulars	($ 000's)
	Regulatory Hearing & OEB Cost Assessment	
1	2007 Actual	5,752
2	2007 Board-Approved	6,000
3	Difference	(248)
	Reasons:	
4	Amortization	(300)
5	Other	52
6	Total difference: 2007 Actual vs. 2007 Board-Approved	(248)
	Outbound Affiliate Services	
7	2007 Actual	(6,476)
8	2007 Board-Approved	(5,741)
9	Difference	(735)
	Reasons:	
10	Other	(735)
11	Total difference: 2007 Actual vs. 2007 Board-Approved	(735)
	Inbound Affiliate Services	
12	2007 Actual	6,303
13	2007 Board-Approved	11,933
14	Difference	(5,630)
	Reasons:	
15	Other	(5,630)
16	Total difference: 2007 Actual vs. 2007 Board-Approved	(5,630)
	Bad Debt	
17	2007 Actual	7,300
18	2007 Board-Approved	11,600
19	Difference	(4,300)
	Reasons:	
20	WACOG and bad debt experience	(4,300)
21	Total difference: 2007 Actual vs. 2007 Board-Approved	(4,300)
	Other	
22	2007 Actual	101
23	2007 Board-Approved	100
24	Difference	1
	Reasons:	
25	Other	1
26	Total difference: 2007 Actual vs. 2007 Board-Approved	1

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars ($000s)	Actual 2008	Actual 2007	Difference	%
		(a)	(b)	(c)	(d)
1	Salaries/Wages	172,275	164,371	7,904	4.81%
2	Benefits	51,366	56,364	(4,998)	(8.87%)
3	Materials	10,696	9,973	723	7.25%
4	Employee Expenses/Training	13,714	12,034	1,680	13.96%
5	Contract Services	55,317	51,194	4,123	8.05%
6	Consulting	8,269	7,277	992	13.64%
7	General	21,837	18,032	3,805	21.10%
8	Transportation and Maintenance	8,159	7,317	842	11.51%
9	Company Used Gas	3,548	3,167	381	12.01%
10	Utility Costs	3,534	3,316	218	6.58%
11	Communications	8,225	7,981	244	3.05%
12	Demand Side Management Programs	12,471	11,569	902	7.80%
13	Advertising	1,544	2,118	(574)	(27.10%)
14	Insurance	7,240	8,030	(790)	(9.84%)
15	Donations	451	377	74	19.54%
16	Financial	2,117	1,661	456	27.43%
17	Lease	3,198	3,381	(183)	(5.42%)
18	Cost Recovery from Third Parties	(3,770)	(3,289)	(481)	14.64%
19	Computers	4,263	4,102	161	3.94%
20	Regulatory Hearing & OEB Cost Assessment	4,488	5,752	(1,264)	(21.97%)
21	Outbound Affiliate Services	(7,768)	(6,476)	(1,292)	19.96%
22	Inbound Affiliate Services	5,870	6,303	(433)	(6.87%)
23	Bad Debt	9,100	7,300	1,800	24.66%
24	Other	237	101	136	134.82%
25	Total Gross Operating and Maintenance Expense	396,381	381,955	14,426	3.78%
26	Indirect Capitalization	(52,675)	(47,275)	(5,400)	11.42%
27	Direct Capitalization	(8,591)	(7,251)	(1,340)	18.48%
28	Total Utility Operating and Maintenance Expense	335,115	327,429	7,686	2.35%
29	Non-Utility Allocations	(10,123)	(7,127)	(2,996)	42.03%
30	Total Net Utility Operating and Maintenance Expense	324,992	320,302	4,690	1.46%
31	Excess Utility Cross-Charge Surcharge	(2,261)	(2,261)	-	0.00%
32	Total Net Utility O&M Less Cross-Charge Surcharge	322,731	318,041	4,690	1.47%

UNION GAS LIMITED

Operating and Maintenance Expense by Cost Type

2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Salaries / Wages	
1	2008 Actual	172,275
2	2007 Actual	164,371
3	Difference	7,904
	Reasons:	
4	Incentive accrual/payout	100
5	Merit increase	5,900
6	Pay equity adjustment (2007)	800
7	Other	1,104
8	Total difference: 2008 Actual vs. 2007 Actual	7,904
	Benefits	
9	2008 Actual	51,366
10	2007 Actual	56,364
11	Difference	(4,998)
	Reasons:	
12	Increased non pension benefit costs	1,200
13	Decreased pension benefit costs	(6,200)
14	Other	2
15	Total difference: 2008 Actual vs. 2007 Actual	(4,998)
	Materials	
16	2008 Actual	10,696
17	2007 Actual	9,973
18	Difference	723
	Reasons:	
19	Rolls Royce contract cancellation	1,300
20	Other	(577)
21	Total difference: 2008 Actual vs. 2007 Actual	723

UNION GAS LIMITED

Operating and Maintenance Expense by Cost Type

2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Employee Expenses / Training	
1	2008 Actual	13,714
2	2007 Actual	12,034
3	Difference	1,680
	Reasons:	
4	Mileage and travel	567
5	Employee training	246
6	Meals and accommodation	613
7	Other	254
8	Total difference: 2008 Actual vs. 2007 Actual	1,680
	Contract Services	
9	2008 Actual	55,317
10	2007 Actual	51,194
11	Difference	4,123
	Reasons:	
12	Integrity work	1,000
13	Distribution contract work	1,200
14	Inflation	1,000
15	Other	923
16	Total difference: 2008 Actual vs. 2007 Actual	4,123
	Consulting	
17	2008 Actual	8,269
18	2007 Actual	7,277
19	Difference	992
	Reasons:	
20	International Financial Reporting Standards (IFRS)	900
21	Other	92
22	Total difference: 2008 Actual vs. 2007 Actual	992

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	General	
1	2008 Actual	21,837
2	2007 Actual	18,032
3	Difference	3,805
	Reasons:	
4	Cushion gas OEB decision (2007)	3,253
5	Other	552
6	Total difference: 2008 Actual vs. 2007 Actual	3,805
	Transportation and Maintenance	
7	2008 Actual	8,159
8	2007 Actual	7,317
9	Difference	842
	Reasons:	
10	Higher fuel prices	842
11	Total difference: 2008 Actual vs. 2007 Actual	842
	Company Used Gas	
12	2008 Actual	3,548
13	2007 Actual	3,167
14	Difference	381
	Reasons:	
15	2007 retroactive gas pressure adjustment	300
16	Volume and price	81
17	Total difference: 2008 Actual vs. 2007 Actual	381
	Utility Costs	
18	2008 Actual	3,534
19	2007 Actual	3,316
20	Difference	218
	Reasons:	
21	Increased utility costs	218
22	Total difference: 2008 Actual vs. 2007 Actual	218

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Communications	
1	2008 Actual	8,225
2	2007 Actual	7,981
3	Difference	244
	Reasons:	
4	Other	244
5	Total difference: 2008 Actual vs. 2007 Actual	244
	Demand Side Management Programs	
6	2008 Actual	12,471
7	2007 Actual	11,569
8	Difference	902
	Reasons:	
9	DSM program costs	902
10	Total difference: 2008 Actual vs. 2007 Actual	902
	Advertising	
11	2008 Actual	1,544
12	2007 Actual	2,118
13	Difference	(574)
	Reasons:	
14	Less advertising spend in 2008	(574)
15	Total difference: 2008 Actual vs. 2007 Actual	(574)
	Insurance	
16	2008 Actual	7,240
17	2007 Actual	8,030
18	Difference	(790)
	Reasons:	
19	Lower insurance premiums	(790)
20	Total difference: 2008 Actual vs. 2007 Actual	(790)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Donations	
1	2008 Actual	451
2	2007 Actual	377
3	Difference	74
	Reasons:	
4	Other	74
5	Total difference: 2008 Actual vs. 2007 Actual	74
	Financial	
6	2008 Actual	2,117
7	2007 Actual	1,661
8	Difference	456
	Reasons:	
9	Other	456
10	Total difference: 2008 Actual vs. 2007 Actual	456
	Lease	
11	2008 Actual	3,198
12	2007 Actual	3,381
13	Difference	(183)
	Reasons:	
14	Other	(183)
15	Total difference: 2008 Actual vs. 2007 Actual	(183)
	Cost Recovery from Third Parties	
16	2008 Actual	(3,770)
17	2007 Actual	(3,289)
18	Difference	(481)
	Reasons:	
19	Other	(481)
20	Total difference: 2008 Actual vs. 2007 Actual	(481)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Computers	
1	2008 Actual	4,263
2	2007 Actual	4,102
3	Difference	161
	Reasons:	
4	Other	161
5	Total difference: 2008 Actual vs. 2007 Actual	161
	Regulatory Hearing & OEB Cost Assessment	
6	2008 Actual	4,488
7	2007 Actual	5,752
8	Difference	(1,264)
	Reasons:	
9	Higher intervenor costs in 2007	(500)
10	Other	(764)
11	Total difference: 2008 Actual vs. 2007 Actual	(1,264)
	Outbound Affiliate Services	
12	2008 Actual	(7,768)
13	2007 Actual	(6,476)
14	Difference	(1,292)
	Reasons:	
15	Other	(1,292)
16	Total difference: 2008 Actual vs. 2007 Actual	(1,292)
	Inbound Affiliate Services	
17	2008 Actual	5,870
18	2007 Actual	6,303
19	Difference	(433)
	Reasons:	
20	Other	(433)
21	Total difference: 2008 Actual vs. 2007 Actual	(433)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars	($ 000's)
	Bad Debt	
1	2008 Actual	9,100
2	2007 Actual	7,300
3	Difference	1,800
	Reasons:	
4	WACOG and bad debt experience	1,800
5	Total difference: 2008 Actual vs. 2007 Actual	1,800
	Other	
6	2008 Actual	237
7	2007 Actual	101
8	Difference	136
	Reasons:	
9	Other	136
10	Total difference: 2008 Actual vs. 2007 Actual	136

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars ($000s)	Actual 2009	Actual 2008	Difference	%
		(a)	(b)	(c)	(d)
1	Salaries/Wages	175,066	172,275	2,791	1.62%
2	Benefits	52,919	51,366	1,553	3.02%
3	Materials	10,693	10,696	(3)	(0.03%)
4	Employee Expenses/Training	10,888	13,714	(2,826)	(20.61%)
5	Contract Services	56,107	55,317	790	1.43%
6	Consulting	6,689	8,269	(1,580)	(19.11%)
7	General	19,940	21,837	(1,897)	(8.69%)
8	Transportation and Maintenance	7,645	8,159	(514)	(6.30%)
9	Company Used Gas	3,373	3,548	(175)	(4.92%)
10	Utility Costs	3,236	3,534	(298)	(8.43%)
11	Communications	7,600	8,225	(625)	(7.60%)
12	Demand Side Management Programs	14,391	12,471	1,920	15.40%
13	Advertising	1,569	1,544	25	1.62%
14	Insurance	7,763	7,240	523	7.23%
15	Donations	501	451	50	11.06%
16	Financial	2,918	2,117	801	37.82%
17	Lease	3,479	3,198	281	8.80%
18	Cost Recovery from Third Parties	(5,363)	(3,770)	(1,593)	42.24%
19	Computers	4,678	4,263	415	9.74%
20	Regulatory Hearing & OEB Cost Assessment	3,653	4,488	(835)	(18.61%)
21	Outbound Affiliate Services	(9,312)	(7,768)	(1,544)	19.87%
22	Inbound Affiliate Services	7,306	5,870	1,436	24.47%
23	Bad Debt	8,600	9,100	(500)	(5.49%)
24	Other	739	237	502	212.21%
25	Total Gross Operating and Maintenance Expense	395,078	396,381	(1,303)	(0.33%)
26	Indirect Capitalization	(51,246)	(52,675)	1,429	(2.71%)
27	Direct Capitalization	(8,348)	(8,591)	243	(2.82%)
28	Total Utility Operating and Maintenance Expense	335,484	335,115	369	0.11%
29	Non-Utility Allocations	(15,159)	(10,123)	(5,036)	49.75%
30	Total Net Utility Operating and Maintenance Expense	320,325	324,992	(4,667)	(1.44%)
31	Excess Utility Cross-Charge Surcharge	(2,261)	(2,261)	-	0.00%
32	Total Net Utility O&M Less Cross-Charge Surcharge	318,064	322,731	(4,667)	(1.45%)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Salaries / Wages	
1	2009 Actual	175,066
2	2008 Actual	172,275
3	Difference	2,791
	Reasons:	
4	Incentive Payout	(1,261)
5	Merit Increase @2.5%	4,305
6	Other	(253)
7	Total difference: 2009 Actual vs. 2008 Actual	2,791
	Benefits	
8	2009 Actual	52,919
9	2008 Actual	51,366
10	Difference	1,553
	Reasons:	
11	Decreased Benefit Costs	(1,389)
12	Increased Pension Costs	2,926
13	Other	16
14	Total difference: 2009 Actual vs. 2008 Actual	1,553
	Materials	
15	2009 Actual	10,693
16	2008 Actual	10,696
17	Difference	(3)
	Reasons:	
18	Other	(3)
19	Total difference: 2009 Actual vs. 2008 Actual	(3)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Employee Expenses / Training	
1	2009 Actual	10,888
2	2008 Actual	13,714
3	Difference	(2,826)
	Reasons:	
4	Lower meals and accommodation expense	(1,062)
5	Lower mileage and travel expense	(906)
6	Lower employee training expense	(430)
7	Other	(428)
8	Total difference: 2009 Actual vs. 2008 Actual	(2,826)
	Contract Services	
9	2009 Actual	56,107
10	2008 Actual	55,317
11	Difference	790
	Reasons:	
12	Increased IT related spend	649
13	Other	141
14	Total difference: 2009 Actual vs. 2008 Actual	790
	Consulting	
15	2009 Actual	6,689
16	2008 Actual	8,269
17	Difference	(1,580)
	Reasons:	
18	Business Transformation Office Consulting in 2008	(953)
19	Implementation of Natural Gas and Electricity Interface Review in 2008	(583)
20	International Financial Reporting Standards Conversion	233
21	Other	(277)
22	Total difference: 2009 Actual vs. 2008 Actual	(1,580)
	General	
23	2009 Actual	19,940
24	2008 Actual	21,837
25	Difference	(1,897)
	Reasons:	
26	Inflation	(437)
27	Decreased Integrity spend in 2009: pre-spent in 2008	(1,250)
28	Other	(210)
29	Total difference: 2009 Actual vs. 2008 Actual	(1,897)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Transportation and Maintenance	
1	2009 Actual	7,645
2	2008 Actual	8,159
3	Difference	(514)
	Reasons:	
4	Lower fuel prices	(514)
5	Total difference: 2009 Actual vs. 2008 Actual	(514)
	Company Used Gas	
6	2009 Actual	3,373
7	2008 Actual	3,548
8	Difference	(175)
	Reasons:	
9	Other	(175)
10	Total difference: 2009 Actual vs. 2008 Actual	(175)
	Utility Costs	
11	2009 Actual	3,236
12	2008 Actual	3,534
13	Difference	(298)
	Reasons:	
14	Other	(298)
15	Total difference: 2009 Actual vs. 2008 Actual	(298)
	Communications	
16	2009 Actual	7,600
17	2008 Actual	8,225
18	Difference	(625)
	Reasons:	
19	Other	(625)
20	Total difference: 2009 Actual vs. 2008 Actual	(625)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Demand Side Management Programs	
1	2009 Actual	14,391
2	2008 Actual	12,471
3	Difference	1,920
	Reasons:	
4	DSM program costs	1,920
5	Total difference: 2009 Actual vs. 2008 Actual	1,920
	Advertising	
6	2009 Actual	1,569
7	2008 Actual	1,544
8	Difference	25
	Reasons:	
9	Other	25
10	Total difference: 2009 Actual vs. 2008 Actual	25
	Insurance	
11	2009 Actual	7,763
12	2008 Actual	7,240
13	Difference	523
	Reasons:	
14	Lower insurance premiums	523
15	Total difference: 2009 Actual vs. 2008 Actual	523
	Donations	
16	2009 Actual	501
17	2008 Actual	451
18	Difference	50
	Reasons:	
19	Other	50
20	Total difference: 2009 Actual vs. 2008 Actual	50

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Financial	
1	2009 Actual	2,918
2	2008 Actual	2,117
3	Difference	801
	Reasons:	
4	Other	801
5	Total difference: 2009 Actual vs. 2008 Actual	801
	Lease	
6	2009 Actual	3,479
7	2008 Actual	3,198
8	Difference	281
	Reasons:	
9	Other	281
10	Total difference: 2009 Actual vs. 2008 Actual	281
	Cost Recovery from Third Parties	
11	2009 Actual	(5,363)
12	2008 Actual	(3,770)
13	Difference	(1,593)
	Reasons:	
14	Higher level of cost recovery in 2009	(1,658)
15	Other	65
16	Total difference: 2009 Actual vs. 2008 Actual	(1,593)
	Computers	
17	2009 Actual	4,678
18	2008 Actual	4,263
19	Difference	415
	Reasons:	
20	Other	415
21	Total difference: 2009 Actual vs. 2008 Actual	415

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Regulatory Hearing & OEB Cost Assessment	
1	2009 Actual	3,653
2	2008 Actual	4,488
3	Difference	(835)
	Reasons:	
4	OEB amortization in 2008 only	(1,226)
5	Other	391
6	Total difference: 2009 Actual vs. 2008 Actual	(835)
	Outbound Affiliate Services	
7	2009 Actual	(9,312)
8	2008 Actual	(7,768)
9	Difference	(1,544)
	Reasons:	
10	New affiliate agreements in 2009	(1,558)
11	Other	14
12	Total difference: 2009 Actual vs. 2008 Actual	(1,544)
	Inbound Affiliate Services	
13	2009 Actual	7,306
14	2008 Actual	5,870
15	Difference	1,436
	Reasons:	
16	New affiliate agreements in 2009	1,415
17	Other	21
18	Total difference: 2009 Actual vs. 2008 Actual	1,436

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars	($ 000's)
	Bad Debt	
1	2009 Actual	8,600
2	2008 Actual	9,100
3	Difference	(500)
	Reasons:	
4	WACOG and bad debt experience	(500)
5	Total difference: 2009 Actual vs. 2008 Actual	(500)
	Other	
6	2009 Actual	739
7	2008 Actual	237
8	Difference	502
	Reasons:	
9	Other	502
10	Total difference: 2009 Actual vs. 2008 Actual	502

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Particulars ($000s)	Actual 2010	Actual 2009	Difference	%
		(a)	(b)	(c)	(d)
1	Salaries/Wages	183,249	175,066	8,183	4.67%
2	Benefits	70,861	52,919	17,942	33.90%
3	Materials	9,631	10,693	(1,062)	(9.93%)
4	Employee Expenses/Training	11,783	10,888	895	8.22%
5	Contract Services	57,335	56,107	1,228	2.19%
6	Consulting	7,506	6,689	817	12.21%
7	General	21,211	19,940	1,271	6.37%
8	Transportation and Maintenance	7,892	7,645	247	3.23%
9	Company Used Gas	2,451	3,373	(922)	(27.34%)
10	Utility Costs	3,704	3,236	468	14.47%
11	Communications	6,780	7,600	(820)	(10.78%)
12	Demand Side Management Programs	16,438	14,391	2,047	14.22%
13	Advertising	1,860	1,569	291	18.58%
14	Insurance	8,507	7,763	744	9.58%
15	Donations	749	501	248	49.57%
16	Financial	2,077	2,918	(841)	(28.81%)
17	Lease	3,632	3,479	153	4.39%
18	Cost Recovery from Third Parties	(4,641)	(5,363)	722	(13.46%)
19	Computers	4,922	4,678	244	5.21%
20	Regulatory Hearing & OEB Cost Assessment	3,126	3,653	(527)	(14.42%)
21	Outbound Affiliate Services	(10,182)	(9,312)	(870)	9.34%
22	Inbound Affiliate Services	9,462	7,306	2,156	29.51%
23	Bad Debt	5,075	8,600	(3,525)	(40.98%)
24	Other	249	739	(490)	(66.28%)
25	Total Gross Operating and Maintenance Expense	423,677	395,078	28,599	7.24%
26	Indirect Capitalization	(46,289)	(51,246)	4,957	(9.67%)
27	Direct Capitalization	(13,978)	(8,348)	(5,630)	67.44%
28	Total Utility Operating and Maintenance Expense	363,410	335,484	27,926	8.32%
29	Non-Utility Allocations	(11,776)	(15,159)	3,383	(22.32%)
30	Total Net Utility Operating and Maintenance Expense	351,634	320,325	31,309	9.77%
31	Excess Utility Cross-Charge Surcharge	(2,261)	(2,261)	-	0.00%
32	Total Net Utility O&M Less Cross-Charge Surcharge	349,373	318,064	31,309	9.77%

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Salaries / Wages	
1	2010 Actual	183,249
2	2009 Actual	175,066
3	Difference	8,183
	Reasons:	
4	Incentive Accrual/Payout	4,600
5	Merit Increase @2.5%	4,710
6	Severances	(828)
7	Other	(299)
8	Total difference: 2010 Actual vs. 2009 Actual	8,183
	Benefits	
9	2010 Actual	70,861
10	2009 Actual	52,919
11	Difference	17,942
	Reasons:	
12	Higher flex benefit costs	2,243
13	2009 flex benefit contribution reduction	1,300
14	Higher legislated benefit costs	219
15	WSIB NEER surcharge	600
16	Increased pension costs	13,300
17	Other	280
18	Total difference: 2010 Actual vs. 2009 Actual	17,942
	Materials	
19	2010 Actual	9,631
20	2009 Actual	10,693
21	Difference	(1,062)
	Reasons:	
22	2009 Lobo repair (offset in recovery)	(1,000)
23	Other	(62)
24	Total difference: 2010 Actual vs. 2009 Actual	(1,062)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Employee Expenses / Training	
1	2010 Actual	11,783
2	2009 Actual	10,888
3	Difference	895
	Reasons:	
4	Relocation costs	(154)
5	Meals and accommodation expense	585
6	Mileage and travel expense	373
7	Employee training expense	249
8	Other	(158)
9	Total difference: 2010 Actual vs. 2009 Actual	895
	Contract Services	
10	2010 Actual	57,335
11	2009 Actual	56,107
12	Difference	1,228
	Reasons:	
13	Maintenance (station painting, easement)	2,400
14	2009 Bright Lobo repairs	(700)
15	2009 Locate activity higher than 2010	(300)
16	Other	(172)
17	Total difference: 2010 Actual vs. 2009 Actual	1,228
	Consulting	
18	2010 Actual	7,506
19	2009 Actual	6,689
20	Difference	817
	Reasons:	
21	Closed Loop Management System development	400
22	Other	417
23	Total difference: 2010 Actual vs. 2009 Actual	817
	General	
24	2010 Actual	21,211
25	2009 Actual	19,940
26	Difference	1,271
	Reasons:	
27	HST savings deferral	200
28	MOL asbestos issue	200
29	Fraud issue	700
30	Other	171
31	Total difference: 2010 Actual vs. 2009 Actual	1,271

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Transportation and Maintenance	
1	2010 Actual	7,892
2	2009 Actual	7,645
3	Difference	247
	Reasons:	
4	Volume and price	247
5	Total difference: 2010 Actual vs. 2009 Actual	247
	Company Used Gas	
6	2010 Actual	2,451
7	2009 Actual	3,373
8	Difference	(922)
	Reasons:	
9	Volume and price	(700)
10	Byron meter - 2 years of charges in 2009	(200)
11	Other	(22)
12	Total difference: 2010 Actual vs. 2009 Actual	(922)
	Utility Costs	
13	2010 Actual	3,704
14	2009 Actual	3,236
15	Difference	468
	Reasons:	
16	Increased utility costs	468
17	Total difference: 2010 Actual vs. 2009 Actual	468
	Communications	
18	2010 Actual	6,780
19	2009 Actual	7,600
20	Difference	(820)
	Reasons:	
21	Telemetry provider change	(300)
22	Bell and Telus credits	(200)
23	Conversion savings	(100)
24	Other	(220)
25	Total difference: 2010 Actual vs. 2009 Actual	(820)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Demand Side Management Programs	
1	2010 Actual	16,438
2	2009 Actual	14,391
3	Difference	2,047
	Reasons:	
4	DSM program costs	2,047
5	Total difference: 2010 Actual vs. 2009 Actual	2,047
	Advertising	
6	2010 Actual	1,860
7	2009 Actual	1,569
8	Difference	291
	Reasons:	
9	Notice of rates proceeding	100
10	Other	191
11	Total difference: 2010 Actual vs. 2009 Actual	291
	Insurance	
12	2010 Actual	8,507
13	2009 Actual	7,763
14	Difference	744
	Reasons:	
15	Higher insurance premiums	744
16	Total difference: 2010 Actual vs. 2009 Actual	744
	Donations	
17	2010 Actual	749
18	2009 Actual	501
19	Difference	248
	Reasons:	
20	Other	248
21	Total difference: 2010 Actual vs. 2009 Actual	248

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Financial	
1	2010 Actual	2,077
2	2009 Actual	2,918
3	Difference	(841)
	Reasons:	
4	2009 Excise Tax credit	200
5	2009 PST assessment	(1,200)
6	Other	159
7	Total difference: 2010 Actual vs. 2009 Actual	(841)
	Lease	
8	2010 Actual	3,632
9	2009 Actual	3,479
10	Difference	153
	Reasons:	
11	Other	153
12	Total difference: 2010 Actual vs. 2009 Actual	153
	Cost Recovery from Third Parties	
13	2010 Actual	(4,641)
14	2009 Actual	(5,363)
15	Difference	722
	Reasons:	
16	Lobo insurance recovery	1,000
17	Aid to construct on project billings	(300)
18	Other	22
19	Total difference: 2010 Actual vs. 2009 Actual	722
	Computers	
20	2010 Actual	4,922
21	2009 Actual	4,678
22	Difference	244
	Reasons:	
23	Other	244
24	Total difference: 2010 Actual vs. 2009 Actual	244

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Notes:	($ 000's)
	Regulatory Hearing & OEB Cost Assessment	
1	2010 Actual	3,126
2	2009 Actual	3,653
3	Difference	(527)
	Reasons:	
4	Other	(527)
5	Total difference: 2010 Actual vs. 2009 Actual	(527)
	Outbound Affiliate Services	
6	2010 Actual	(10,182)
7	2009 Actual	(9,312)
8	Difference	(870)
	Reasons:	
9	Other	(870)
10	Total difference: 2010 Actual vs. 2009 Actual	(870)
	Inbound Affiliate Services	
11	2010 Actual	9,462
12	2009 Actual	7,306
13	Difference	2,156
	Reasons:	
14	Other	2,156
15	Total difference: 2010 Actual vs. 2009 Actual	2,156
	Bad Debt	
16	2010 Actual	5,075
17	2009 Actual	8,600
18	Difference	(3,525)
	Reasons:	
19	Lower WACOG and bad debt experience	(3,525)
20	Total difference: 2010 Actual vs. 2009 Actual	(3,525)
	Other	
21	2010 Actual	249
22	2009 Actual	739
23	Difference	(490)
	Reasons:	
24	Other	(490)
25	Total difference: 2010 Actual vs. 2009 Actual	(490)

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D3, Tab 3, Schedule 1

The 2013 budget for Regulatory, Municipal Relations and Public Affairs is $16.982 million. Please provide a detailed breakdown of all of the items included in this budget and the associated costs. Please provide the 2007 Board approved and actuals for 2007-2011. Please provide the same level of detail for 2012.

Response:

Please see Attachment 1.

Union Gas Limited

Regulatory, Municipal Relations and Public Affairs Budget

Line No.	Particulars ($)	2007 (1) Board Filed	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 (2) Actual	2012 Budget	2013 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Salaries/Wages	3,088,050	3,316,901	3,326,456	3,151,864	3,393,007	4,786,262	4,757,589	4,810,672
2	Employee Benefits (non-pension)	-	-	-	-	-	37,374	66,365	67,759
3	Employee Expenses + Training	445,209	251,307	286,457	241,104	213,504	413,604	646,032	548,896
4	Contract Services	116,477	78,125	69,289	55,165	65,035	233,015	224,553	229,267
5	Consulting - Regulatory	806,129	123,867	329,637	18,430	48,424	668,106	599,660	612,593
6	Outside Legal Counsel - Regulatory	500,000	848,036	645,546	433,058	319,311	436,757	910,186	754,170
7	Consulting - Other	31,855	37,275	15,931	5,190	1,155	15,375	64,618	65,944
8	Materials	27,019	26,546	35,144	15,051	27,837	23,645	35,225	35,971
9	General & Other	127,710	50,580	50,513	272,335	109,436	289,027	1,113,004	1,118,069
10	Transportation	-	-	-	-	-	50	-	-
11	Computers	5,110	10,350	11,555	14,448	27,868	22,648	28,749	29,353
12	Communications	19,618	23,723	33,487	34,377	25,393	33,757	57,957	58,393
13	Advertising	44,692	140,175	147,130	149,911	306,438	527,558	387,583	389,422
14	Lease	-	3,098,557	3,008,634	3,278,531	3,326,905	3,448,829	3,922,145	3,961,890
15	Amortization of Rate Case Costs	4,500,000	1,200,000	1,226,128	-	-	-	-	-
16	OEB Cost Assessment Charges	-	3,454,854	2,511,016	2,652,276	2,539,738	2,460,049	3,000,000	3,000,000
17	Intervenor Costs	-	1,096,905	750,744	995,890	586,354	845,791	2,200,000	1,500,000
18	OEB Cost Assessment (3)	5,120,519	-	-	-	-	-	-	-
19	Recovery Cost	-	-	(17,640)	-	-	-	-	-
20	Affiliates	-	(66,496)	(106,707)	(115,077)	-	-	-	-
Total Direct		14,832,388	13,690,704	12,323,319	11,202,553	10,990,402	14,241,847	18,013,665	16,982,428

Notes: (1) Board-approved by function group is not available. Board filed has been provided.
(2) Municipal Relations and Aboriginal Affairs did not join the Regulatory group until 2011.
(3) "OEB Cost Assessment Charges" and "Intervenor Costs" expenditures are not separated for budget purposes in the 2007 Board Field Numbers.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D3, Tab 3, Schedule 1

The 2013 budget for Government Affairs/ Relations is $993,000. Please provide a detailed breakdown of all of the items included in this budget and the associated costs. Please provide the 2007 applied for amounts and actuals for 2007-2011. Please provide the same level of detail for 2012.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Government Affairs / Relations Budget

Line No.	Particulars ($)	2007 [1] Board Filed	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 [2] Actual	2012 Budget	2013 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Salaries/Wages	465,061	448,862	599,856	526,360	543,372	374,919	460,707	473,023
2	Employee Benefits (non-pension) [3]	51,000	46,822	48,721	55,742	63,926	-	-	-
3	Employee Expenses + Training	126,750	121,921	151,471	115,877	117,901	82,897	183,635	187,402
4	Contract Services	136,500	164,276	143,445	47,753	40,605	7,100	3,492	3,565
5	Consulting	80,000	392,632	68,019	46,556	104,850	203,756	174,996	174,996
6	Materials	2,500	19,180	11,599	4,390	1,422	454	-	-
7	General & Other	93,850	188,459	199,742	241,981	249,119	126,915	123,037	125,123
8	Communications	5,650	9,983	12,733	11,952	6,690	4,335	5,400	5,400
9	Advertising	261,750	115,661	119,341	128,072	174,894	29,308	21,441	21,891
10	Affiliates	-	-	(322)	-	-	-	-	-
Total Direct		1,223,061	1,507,795	1,354,605	1,178,683	1,302,779	829,685	974,711	993,405

Notes:

(1) Board approved by function group is not available. Board filed has been provided.

(2) Municipal Relations & Aboriginal Affairs did not join the Regulatory group until 2011.

(3) Employee benefits (non-pension) 2007 to 2010 were included in the Municipal Relations group.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D3, Tab 3, Schedule 1

For the IT expenditures at lines 15, 16 and 17 please provide a detailed breakdown of each of the items included in these budgets for 2007-2013 (actuals where available). Please include applied for numbers for 2007 and budgets for 2012 and 2013.

Response:

Please see Attachments 1, 2 and 3.

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31
IT - Information Systems (Line 15)

Line No.	Particulars ($000s)	Budget 2007 (a)	Actual 2007 (b)	Board Filed 2007 (c)	Budget 2008 (d)	Actual 2008 (e)	Budget 2009 (f)	Actual 2009 (g)	Budget 2010 (h)	Actual 2010 (i)	Budget 2011 (j)	Actual 2011 (k)	Budget 2012 (l)	Budget 2013 (m)
1	Salaries and Wages	7,759.5	6,660.4	8,302.5	6,913.8	6,765.6	6,745.9	6,580.2	6,588.8	7,618.7	7,783.5	7,563.1	7,381.7	7,668.4
2	Benefits	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Materials	23.1	349.6	23.6	18.6	7.0	11.6	0.4	11.8	5.4	11.8	11.1	11.9	12.1
4	Employee and Training	372.4	481.2	442.4	343.9	376.2	342.3	272.2	320.2	314.9	320.2	461.3	317.7	321.1
5	Contract Services	70.4	49.5	49.2	24.0	92.2	46.8	291.5	279.6	288.0	279.6	929.6	1,000.3	866.3
6	Consulting	-	124.9	11.0	-	8.7	-	513.3	230.0	432.5	230.0	104.6	232.5	235.0
7	General	5.8	11.1	5.8	1.0	13.5	2.5	13.0	2.0	5.8	2.0	3.6	2.0	2.0
8	Transportation	-	-	-	-	-	-	-	-	-	-	0.0	-	-
9	Own Used Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Utility	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Communication	50.9	48.7	45.9	53.5	43.4	48.0	41.8	48.9	33.2	48.9	37.1	49.4	49.9
12	Computer	1,775.7	1,822.5	2,859.3	1,662.6	1,780.8	2,379.1	1,885.2	2,260.0	2,254.3	2,320.0	2,393.1	2,811.4	2,854.0
13	Maintenance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
14	DSM Program Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Advertising and Promotion	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Insurance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Donations	-	-	-	-	0.3	-	-	-	-	-	-	-	-
18	Financial Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Industry Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Capital Clearing	-	7.7	-	-	15.0	-	7.3	-	3.8	-	5.5	-	-
22	Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Affiliate Transactions [1]	(77.0)	(143.0)	-	-	(326.8)	(339.9)	(347.5)	-	-	-	-	-	-
24	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	9,980.8	9,412.6	11,739.7	9,017.3	8,775.7	9,236.3	9,257.4	9,741.3	10,956.4	10,996.0	11,509.0	11,807.0	12,008.9

[1] Affiliate Transactions includes affiliate revenue for years 2007 - 2009

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31
IT - Information Technology Infrastructure (Line 16)

Line No.	Particulars ($000s)	Budget 2007 (a)	Actual 2007 (b)	Bd Filed 2007 (c)	Budget 2008 (d)	Actual 2008 (e)	Budget 2009 (f)	Actual 2009 (g)	Budget 2010 (h)	Actual 2010 (i)	Budget 2011 (j)	Actual 2011 (k)	Budget 2012 (l)	Budget 2013 (m)
1	Salaries and Wages	3,248.6	3,407.8	3,815.6	3,434.5	3,333.3	3,608.7	3,513.3	3,624.7	3,302.5	3,590.6	3,586.9	3,606.7	3,659.2
2	Benefits	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Materials	-	11.5	-	7.1	6.5	10.4	3.5	10.4	5.5	4.4	2.7	4.4	4.4
4	Employee and Training	243.2	306.2	250.4	243.3	250.2	267.3	298.5	267.3	302.0	297.3	302.8	291.5	291.5
5	Contract Services	4,241.2	4,542.1	4,248.7	4,803.8	4,860.9	4,873.5	5,265.0	4,775.3	4,441.9	4,087.0	4,008.8	3,954.8	3,822.8
6	Consulting	431.4	484.8	122.3	537.5	520.5	476.9	284.8	282.8	286.9	363.0	214.3	217.2	223.5
7	General	119.6	104.4	119.6	115.7	109.5	113.0	103.7	103.0	87.5	87.6	84.5	42.5	42.5
8	Transportation	-	-	-	-	-	-	-	-	-	-	0.0	-	-
9	Own Used Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Utility	-	-	-	-	-	-	(0.2)	-	-	-	-	-	-
11	Communication	5,526.1	5,633.1	6,100.2	5,821.4	5,662.8	5,604.2	5,418.3	5,519.2	5,042.1	5,154.2	4,735.8	4,119.3	4,222.1
12	Computer	1,393.2	1,236.9	1,657.5	1,257.5	1,510.6	1,624.5	1,799.4	1,730.9	1,667.8	2,016.3	1,781.4	2,215.1	2,453.4
13	Maintenance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
14	DSM Program Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Advertising and Promotion	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Insurance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Donations	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Financial Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Industry Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Capital Clearing	-	30.5	-	-	141.2	128.0	37.0	161.8	82.0	144.4	120.1	112.6	112.6
22	Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Affiliate Transactions (1)	(1,526.3)	(1,765.3)	(1,795.2)	(1,934.3)	(1,916.1)	(1,974.2)	(1,979.4)	-	-	-	-	-	-
24	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	13,676.9	13,991.9	14,519.0	14,286.6	14,479.5	14,732.2	14,743.9	16,475.3	15,218.1	15,744.7	14,837.4	14,563.9	14,832.0

(1) Affiliate Transactions includes affiliate revenue for years 2007 - 2009

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31
IT - Other (Line 17)

Line No.	Particulars ($000s)	Budget 2007 (a)	Actual 2007 (b)	Bd Filed 2007 (c)	Budget 2008 (d)	Actual 2008 (e)	Budget 2009 (f)	Actual 2009 (g)	Budget 2010 (h)	Actual 2010 (i)	Budget 2011 (j)	Actual 2011 (k)	Budget 2012 (l)	Budget 2013 (m)
1	Salaries and Wages	1,002.9	856.8	1,064.4	1,001.8	933.2	1,035.8	1,052.8	1,099.9	1,041.8	1,252.7	1,251.7	1,699.0	1,758.3
2	Benefits	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Materials	5.3	4.9	4.5	8.5	11.0	8.5	9.9	8.7	0.1	11.5	6.5	11.8	12.0
4	Employee and Training	58.5	16.2	61.4	48.7	27.7	48.7	20.8	47.3	36.4	59.2	16.5	91.8	93.3
5	Contract Services	-	50.5	-	-	0.6	-	0.3	-	0.3	-	146.2	50.0	50.0
6	Consulting	90.0	100.7	44.4	80.0	55.7	80.0	-	67.0	5.4	142.2	20.9	142.2	145.0
7	General	6.1	0.7	5.3	3.6	2.9	3.6	2.3	3.8	1.9	8.3	1.0	-	-
8	Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Own Used Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Utility	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Communication	7.1	3.8	6.3	6.4	5.7	6.4	7.1	7.5	6.7	12.2	9.6	19.8	20.2
12	Computer	456.3	399.4	552.2	450.3	376.0	569.6	557.4	623.1	537.2	923.0	675.7	711.6	726.7
13	Maintenance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
14	DSM Program Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Advertising and Promotion	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Insurance Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Donations	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Financial Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Industry Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Capital Clearing	-	-	-	-	-	-	-	-	-	-	6.3	-	-
22	Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Affiliate Transactions (1)	(244.1)	(262.0)	-	(288.1)	(285.0)	(342.6)	(340.2)	-	-	-	-	-	-
24	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	1,382.0	1,171.1	1,738.5	1,311.3	1,127.6	1,410.1	1,310.4	1,857.2	1,629.8	2,409.1	2,134.3	2,726.2	2,805.5

(1) Affiliate Transactions includes affiliate revenue for years 2007 - 2009

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit A1, Tab 13, Schedule 1

Union has filed its Conditions of Service. Please identify all of the changes made since 2007. What is the annual incremental cost of adopting those changes?

Response:

The Gas Services Guidelines was first posted on uniongas.com on June 25, 2008. No updates were made until it was replaced with the Conditions of Service. The Conditions of Service was first filed in the original EB-2011-0210 Application dated November 10, 2011. Updates since that time were filed and posted on January 1, 2012, March 5, 2012 and April 1, 2012.

The Conditions of Service was filed and posted on uniongas.com with the inclusion of the following modifications for residential customers, effective March 5, 2012:

Bill Issuance and Payment
Union will now accept credit cards for bill payments.

Union will provide customers requiring emergency financial assistance a total of 21 days to secure social assistance before a collection action is initiated for non-payment.

Union has extended the bill payment period for the Late Payment Charge to be applied from 16 to 20 days. This change was implemented effective January 1, 2012.

Correction of Billing Errors
In the rare event that an adjustment must be made to the charges that have been billed to a customer's account, Union will provide additional explanations on the customer's bill as to the reasons for the adjustment.

Equal Billing Plan
Customers can now join the Equal Billing Plan during any month of the year. Union will clearly explain how the plan works, including why Union will occasionally adjust monthly instalments to match actual gas usage.

Disconnection for Non-Payment
Union will provide 10 days written notice of a pending disconnection for non-payment of gas charges. The notification will also describe payment options to avoid the disconnection of gas services.

Security Deposits
Customers who are required to pay a security deposit will now be given the choice to pay the deposit in instalments of up to six months duration. Union will continue to provide customers the choice of waiving the required security deposit if they enrol in both the Equal Billing Plan and the Automatic Payment Plan.

Security deposits are designed to cover two months of gas bills. To estimate the total of these two bills, Union will now review two average bills from the past year instead of the two highest bills.

Arrears Management Programs
Customers who have entered into a payment arrangement for an overdue account will be notified in advance when payments are due. Customers will also be given 10 days notice of disconnection if they fail to meet the obligations of the arrangement.

Customers who have security deposits on their accounts may receive additional opportunities to pay their arrears before Union issues a notice of disconnection for non-payment.

Incremental capital expenditures incurred in 2011 and concluding in 2012 to implement the above modifications are approximately $1.550 million. Union will monitor potential operational and lost revenue impacts as a result of the changes described above and may seek recovery through the GDAR Costs deferral account.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference**:** Exhibit D1, Tab 5, Page 4

With regards to the overall DSM budget, please confirm that no stakeholder agreement or Board approval is in place for DSM programs or costs for T1/Rate 100 customers after December 31, 2012.

Response:

As set out on page 26 of the EB-2011-0327 Settlement Agreement:

"The Participating Parties have agreed that the DSM Plan for 2013 and 2014 relating to Large Industrial Rate T1 Rate 100 will not be included in this Agreement, and Union hereby withdraws its requests for approvals of that part of its Plan as set forth in the Application. Union agrees to file a new application and evidence with the Board supporting a Large Industrial Rate T1 / Rate 100 DSM plan for 2013 and 2014 prior to September 1, 2012."

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit D1, Tab 2
Exhibit D1, Summary Schedules 1 and 2
Tab 3, Schedule 1 of Exhibits D3, D4 and D5
Tab 6, Schedule 1 of Exhibits D3, D4 and D5

With respect to these Exhibits, please provide the following additional information:

a) An Exhibit that broadens Exhibit D1, Summary Schedule 1 to include between Columns (a) and (b) additional columns providing Actual information for the years 2007, 2008 and 2009;

b) A new Summary Schedule, comparable to Exhibit D1, Summary Schedule 2, that presents all of the information contained in Exhibit D1, Summary Schedule 2 by "Administrator" in the format presented in Tab 3, Schedule 1 of Exhibits D3, D4 and D5;

c) An Exhibit that broadens the "Year-Over-Year Continuity for O&M" information shown in Table 4 of Exhibit D1, Tab 2 to include the information in lines 2 to 20 leading to the Board approved amount of $325.6M, and then adds the Actual information for 2007 to 2013 inclusive so as to provide a complete continuity presentation by line item for the period 2007 to 2013 inclusive; and

d) A new Exhibit, comparable to Schedule 2 of Tab 6 of Exhibits D3, D4 and D5 "FTE Report by Administrator" showing the FTE Forecast in the Board Approved Revenue Requirement for 2007, followed by Actuals for 2007 to 2011 inclusive, Estimated Actuals for 2012, and Forecasts for 2013, along with the "Variance Explanations" for 2007 to 2013 inclusive.

Response:

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Please see Attachment 3.

d) Please see Attachment 4. There is no change to the 2012 and 2013 FTE budget.

UNION GAS LIMITED
Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Board - Approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Cost of gas	1,135,825	1,154,203	1,169,446	1,023,220	795,549	755,941	721,228	697,838
2	Operating and maintenance	326,222	320,302	324,832	320,325	351,634	371,731	383,774	393,228
3	Depreciation	173,780	168,465	180,253	187,173	190,176	195,477	204,145	196,467
4	Other financing	315	636	535	474	621	343	362	1,179
5	Property and capital taxes	67,709	64,476	64,942	66,638	65,131	60,700	62,916	64,022
6	Other expense	-	-	-	3,050	500	(709)	-	-
7	Income taxes	14,589	26,033	36,277	36,288	30,214	33,119	18,560	6,574
8	Cost of service excluding return	1,718,440	1,734,115	1,776,285	1,637,168	1,433,825	1,416,602	1,390,985	1,359,308

UNION GAS LMIITED
Operating and Maintenance Expense by Administrator
Year Ended December 31

Line No.	Particulars ($000s)	Actual 2007 (3)	Actual 2008	Actual 2009 (2)	Actual 2010	Actual 2011 (5)	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Affiliate Services (Inbound & Outbound)	(173.4)	(1,916.5)	(2,311.9)	(720.0)	(2,738.4)	(2,172.8)	(1,818.0)
2	Audit Services	319.6	373.8	391.8	323.3	301.2	475.8	487.4
3	Bad Debt	7,300.0	9,100.0	8,600.0	5,075.3	4,455.1	6,600.0	6,600.0
4	Business Development, Storage & Transmission	21,217.5	15,032.4	14,890.3	14,592.5	14,870.5	16,010.1	16,615.0
5	Corporate Adjustments	(982.7)	3,594.4	2,589.6	2,783.5	2,662.5	5,640.8	2,831.9
6	Distribution Operations	110,965.1	112,890.8	109,384.9	114,565.1	121,307.0	121,684.9	127,775.5
7	Employee & Labour Relations	82,886.6	78,154.9	78,952.8	101,852.7	114,778.7	106,545.9	108,123.2
8	Energy Conservation	12,605.5	17,000.0	20,570.0	22,627.0	24,889.7	30,954.1	31,842.5
9	Engineering, Construction & STO	34,112.6	41,387.1	40,409.8	42,471.9	44,762.3	45,134.8	47,590.2
10	Environment, Health & Governance	564.3	964.9	641.8	830.0	754.4	862.6	886.9
11	Executive	3,250.0	3,273.8	4,847.0	2,961.7	3,258.5	3,201.2	3,281.4
12	Finance	4,071.6	7,729.2	8,320.5	7,777.9	9,919.1	10,469.0	10,742.4
13	Government Affairs/Relations	1,507.8	1,354.6	1,178.7	1,302.8	829.7	974.7	993.4
14	Insurance	8,282.2	7,480.4	7,932.1	8,780.0	8,315.8	9,012.6	9,484.0
15	IT - Information Systems	9,555.6	9,102.5	9,604.9	10,956.4	11,509.0	11,807.0	12,008.9
16	IT - Information Technology Infrastructure	15,757.2	16,395.6	16,723.4	15,218.1	14,837.4	14,563.9	14,832.0
17	IT - Other	1,433.1	1,412.6	1,650.6	1,629.8	2,134.3	2,726.2	2,805.5
18	Legal	1,024.4	1,193.4	1,053.1	1,269.5	1,265.9	1,383.8	1,406.4
19	Marketing & Customer Care	51,414.0	56,019.0	54,627.4	54,863.9	56,712.1	59,509.1	62,914.0
20	Procurement / Supply Chain	1,818.7	2,213.9	2,152.2	2,226.4	1,713.6	2,015.8	2,078.4
21	Project Systems & Control	-	126.3	466.2	187.4	186.8	202.5	208.9
22	Regulatory, Municipal Relations and Public Affairs	13,757.2	12,429.8	11,317.7	10,990.4	14,241.9	18,013.7	16,982.4
23	Tax	1,268.4	1,067.9	1,085.3	1,111.9	1,174.7	1,171.3	1,208.9
24	Total	381,955.3	396,380.9	395,078.2	423,677.4	452,141.8	466,787.0	479,881.2
25	Indirect Capitalization (OH)	(47,275.2)	(52,675.2)	(51,246.2)	(46,289.6)	(52,220.0)	(50,789.0)	(51,376.0)
26	Direct Captialization (DCC)	(7,250.7)	(8,590.4)	(8,348.0)	(13,978.3)	(15,149.0)	(19,019.1)	(21,651.6)
27	Total Capitalization	(54,525.9)	(61,265.6)	(59,594.2)	(60,267.9)	(67,369.0)	(69,808.1)	(73,027.6)
28	Total	327,429.4	335,115.3	335,484.0	363,409.5	384,772.9	396,978.9	406,853.6
29	Non Utility Allocations (1)	(7,127.0)	(10,122.8)	(12,282.2)	(11,775.9)	(13,041.9)	(13,204.7)	(13,625.3)
30	IFRS Costs	-	-	(2,877.0)	-	-	-	-
31	Total Net Utility Operating and Maintenance Expense	320,302.4	324,992.5	320,324.8	351,633.6	371,731.0	383,774.2	393,228.3
32	Excess Utility Cross-Charge (4)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)	(2,261.0)
33	Total Net Utility O&M Less Cross-Charge	318,041.4	322,731.5	318,063.8	349,372.6	369,470.0	381,513.2	390,967.3

Note:
(1) Includes charitable donations and prior period PST assessment.
(2) 2009 Actuals do not include $9 million related to Lobo C and St. Clair.
(3) 2007 Board-approved balances are not available by Administrator
(4) 2013 Utility Cross-Charge is an estimate and will be updated as part of the cost study.
(5) 2011 Actuals do not include $6 million reduction related to St. Clair.

UNION GAS LIMITED
Year Over Year Continuity for O&M

Line No.	Particulars ($000's)	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	Total
1	Board Approved (RP-2005-0520)	325.6							325.6
2	Prior Period		318.0	322.7	318.1	349.3	369.5	381.5	
3	Salaries/Wages	4.5	7.9	2.8	8.2	8.6	(3.9)	5.8	33.9
4	Benefits	0.7	(5.0)	1.6	17.9	10.3	1.0	(1.1)	25.4
5	Employee Expenses/Training	(0.8)	1.7	(2.8)	0.9	1.7	0.6	0.2	1.5
6	Contract Services	1.1	4.1	0.8	1.3	6.3	0.1	2.7	16.4
7	Consulting	0.8	1.0	(1.5)	0.8	0.2	3.4	2.1	6.8
8	General	(2.6)	3.8	(1.9)	1.3	1.1	(0.7)	0.6	1.6
9	Company Used Gas	(1.8)	0.4	(0.2)	(0.9)	(0.1)	0.1	-	(2.5)
10	Utility Costs	-	0.2	(0.3)	0.5	0.4	0.5	0.1	1.4
11	Communications	-	0.2	(0.6)	(0.8)	(0.4)	(0.2)	0.1	(1.7)
12	Demand Side Management Programs	(0.3)	0.9	2.0	2.0	1.5	5.7	0.6	12.4
13	Insurance	1.0	(0.8)	0.6	0.7	(0.4)	0.5	0.5	2.1
14	Computers	(0.1)	0.2	0.4	0.2	0.4	0.9	0.3	2.3
15	Regulatory Hearing & OEB Cost Assessment	(0.2)	(1.3)	(0.9)	(0.5)	0.2	1.9	(0.9)	(1.7)
16	Affiliate	(6.2)	-	-	(0.7)	(2.0)	0.6	0.4	(7.9)
17	Bad Debt	(4.3)	1.8	(0.5)	(3.5)	(0.6)	2.1	-	(5.0)
18	Other	(1.8)	(0.7)	(3.5)	4.0	1.4	2.0	1.7	3.1
19	Total Capitalization	4.4	(6.7)	1.6	(0.7)	(7.1)	(2.4)	(3.2)	(14.1)
20	Excess Utility Cross-Charge	(0.3)	(3.0)	(2.2)	0.5	(1.3)	(0.2)	(0.4)	(6.9)
21	Total Net Utility O&M Less Cross-Charge	(1.7)							(1.7)
22		(7.6)	4.7	(4.6)	31.2	20.2	12.0	9.5	65.4
23	Current Period	318.0	322.7	318.1	349.3	369.5	381.5	391.0	

UNION GAS LIMITED
FTE Report by Administrator
for the years ending December 31

Line No.	Particulars	Board Filed 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Executive	6	8	6	8	8	8	8	8
2	Business Development	100	141	142	144	146	137	150	152
3	Operations	1,615	1302	1334	1298	1,313	1,297	1,357	1,358
4	Regulatory	120	43	43	45	48	57	61	61
5	Information Technology	152	158	157	158	170	171	177	177
6	Corporate Services	183	458	472	484	477	498	513	515
7	Human Resources	25	37	47	47	49	51	53	46
8	Total	2,201	2,147	2,201	2,183	2,211	2,219	2,319	2,317
9	Vacancy assumption in forecast	(66)						(69)	(69)
10	Forecasted FTE	2,135						2,250	2,248
	Variance explanation:								
	Role additions:								
11	Executive				1				
12	Business Development			1	2	2		3	2
13	Operations			12		5	7	2	1
14	Regulatory				2	3	3		
15	Information Technology				1	1	3	2	
16	Corporate Services			12			8	1	2
17	DSM Roles						3	1	
18	Human Resources		5	6		2	2	1	(7)
	Role reductions:								
19	Executive			(1)					
20	Operations							(4)	
21	Corporate Services						(15)		
22	Additional (less) vacancies		7	(1)	(3)		(3)		
23	IT Contractors to Full Time					11			
24	Timing of tempoary employee contracts			22	2	5			
25	Timing of Seasonal layoffs in Operations			3	(23)	(1)		25	
26	Total Variance		12	54	(18)	28	8	31	(2)

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit D1, Tab 2
Exhibit D1, Summary Schedules 1 and 2
Tab 3, Schedule 1 of Exhibits D3, D4 and D5
Tab 6, Schedule 1 of Exhibits D3, D4 and D5

According to Exhibit D3, Tab 6, Schedule 2, excluding vacancies, Actual FTEs forecast for 2013 are 2,317 compared to 2,211 for 2010, an increase of 106 FTEs. In Exhibit D1, Tab 2 at page 9, it is stated that the 2,248 FTEs for 2013 (which includes 69 vacancies) represents an increase over 2010 year-end Actual of 37 FTEs. Please reconcile this statement with the information that appears in Exhibit D3, Tab 6, Schedule 2 at lines 8 and 10 of Columns A and D.

Response:

The statement in Exhibit D1, Tab 2 at page 9 is comparing column d, line 10 (Forecasted FTE – 2,248), to column a, Line 8 (Total – 2,211) from Exhibit D3, Tab 6, Schedule 2. The difference between these two amounts is 37. The actual 2010 FTE's (Line 8 – 2,211) is net of vacancies which compares to the forecast 2013 FTE's (2,248) at Line 10 which is net of vacancies.

Please see the variance explanations at Exhibit D3, Tab 6, Schedule 2 on the response at Exhibit J.D-1-2-3.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit D1, Tab 2
Exhibit D1, Summary Schedules 1 and 2
Tab 3, Schedule 1 of Exhibits D3, D4 and D5
Tab 6, Schedule 1 of Exhibits D3, D4 and D5

With respect to Regulatory Hearing and OEB Cost Assessment amounts shown at line 20 in Exhibit D1, Summary Schedule 2, and the larger amounts for "Regulatory, Municipal Relations, and Public Affairs" shown at line 22 of Tab 3, Schedule 1 in Exhibits D3, D4 and D5, please provide a complete breakdown of the costs in each of those line items for Actual 2007 to 2012 inclusive, with the details to include a breakdown of Regulatory Hearing expenses in each year by project and services provider.

Response:

Please see the response at Exhibit J.D-1-5-8.

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 3, Schedule 1, page 4

Please provide a copy of the original "prior year – productivity + inflation" budget for 2013, a list of all material adjustments for "new program additions" and "material changes to existing programs", and either an explanation or an evidence reference for each of those adjustments.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Derivation 2013 O&M Budget

Line No.	Particulars ($ millions)		Reference
1	2012 Budget	381.5	D4, Tab 3, Schedule 1
2	Plus merit /promo Increases	6.9	D3, Tab 3, Schedule 2
3	Plus inflation	3.4	
4	Less productivity	(3.4)	
5	Plus customer growth	2.3	
	Additions / Deletions		
6	Pipeline integrity	0.9	Exhibit D3,Tab 3,Schedule 2, p. 3, line 11
7	Market development	2.0	Exhibit D3,Tab 3,Schedule 2, p. 3, line 19
8	Pension benefits	(2.5)	
9	Non pension benefits	1.4	Exhibit D3, Tab 3, Schedule 2, p.2, line 11
10	Regulatory & hearing costs	(0.9)	Exhibit D3, Tab 3, Schedule 2, p.7, line 9
11	Other	(0.6)	
12	2013 Budget	391.0	

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 3, Schedule 1, Appendix B, page 4

Please explain in more detail the box that is headed up "Customer Growth", including the two lines below, and the three dollar figures in each of the three boxes to the right of the heading.

Response:

The $105.71 in Exhibit A2, Tab 3, Schedule 1, Appendix B, p.4 is the estimated O&M associated with adding customers. The cost, included in the estimate are bill inserts, postage, meter reading and maintaining additional distribution services and meter sets.

The cost associated with adding customers is allocated between Distribution Operations (61%) and Marketing & Customer Care (39%). This allocation was based on the 2011 budgeted O&M (net of capitalization and Demand Side Management) for these departments.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 3

Please explain the increase in "Other" (line 14) from 4, in evidence filed (2011-11-10), to 7 in evidence filed (2012-03-27).

Response:

The increase in the "Other" line is a restatement of vehicle depreciation ($2.2 million). On an actual basis, vehicle depreciation is expensed as part of gross O&M and then 100% capitalized through direct capitalization. For consistency, the 2013 Forecast was adjusted to reflect the same accounting process. The $2.2 million increase in gross O&M is offset by an increase in direct capitalization. There is no impact to Net O&M.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Pages 2 and 3

In what years did TCPL offer an FT RAM credit? Were Union's FT RAM revenue subject to the Earnings Sharing Agreement in each year over the recent IRM period? Please discuss, showing amounts of FT RAM credits in each year. If not, why not? Please discuss fully. Were the FT RAM credits Z-factors for each IRM year during which Union participated in them? Please discuss.

Response:

Please see Attachment 1 for a timeline of what years TCPL offered RAM credits. Please see the response at Exhibit J.C-4-7-1 c).

Please see the response at Exhibit J.C-4-7-9 d) for the amount of RAM credits generated by year. RAM credits do not meet the Z-factor criteria in Union's current IRM.

TransCanada
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TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

Tel: (403) 920-2046
Fax: (403) 920-2347
Email: murray_sondergard@transcanada.com

January 16, 2009

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Filed Electronically

Attention: Ms. Claudine Dutil-Berry, Secretary

Dear Ms. Dutil-Berry:

**Re: TransCanada PipeLines Limited ("TransCanada")
Amendments to TransCanada's Canadian Mainline Transportation Tariff**

TransCanada hereby files an application with the National Energy Board ("Board") pursuant to Section 60(1)(b) of the *National Energy Board Act* for an order or orders approving certain amendments to TransCanada's Mainline Transportation Tariff's Interruptible Transportation ("IT") Toll Schedule. The proposed amendments were presented to the Tolls Task Force ("TTF") and were unopposed by the TTF in Resolution 04.2009, FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature, voted on January 7, 2009.

TTF Resolution 04.2009 describes amendments to the IT Toll Schedule to add the current Risk Alleviation Mechanism ("RAM") for Firm Transportation ("FT") Service, Storage Transportation Service ("STS") and Storage Transportation Linked Service ("STS-L") as permanent features of the Mainline transportation services.

The FT-RAM pilot was originally approved by the Board in a letter dated July 15, 2004 as a feature of FT service for a one year period commencing November 1, 2004 per TTF Resolution 02.2004. The FT-RAM pilot was subsequently extended for a period of one year by the Board in a letter dated September 6, 2005 as per TTF Resolution 20.2005 and again by the Board in a letter dated April 21, 2006 as per TTF Resolution 05.2006. Modifications to apply the FT-RAM pilot to short-haul contracts were made effective April 1, 2006 by Board Order TG-1-2006, and in accordance with the Board's decision in RHW-2-2005.. In a letter dated March 2, 2007, the Board approved an additional two-year extension of the FT-RAM pilot commencing November 1, 2007 as per TTF Resolution 03.2007 and extended the FT-RAM pilot to include Storage Transportation Service (STS-RAM) and Storage Transportation Service Linked (STSL-RAM) for a two-year term commencing November 1, 2007 as per TTF Resolution 02.2007.

During the various RAM pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users TransCanada notes that use of the RAM mechanism does not limit the service entitlements of current FT service.

In support of its application, TransCanada attaches for the Board's information blacklined and clean copies of the IT Toll Schedule and a copy of TTF Resolution 04.2009. TransCanada proposes that these changes become effective November 1, 2009.

Should the Board require additional information, please contact Stella Morin at (403) 920-6844 or stella_morin@transcanada.com.

Yours truly,

Original Signed by

Murray Sondergard
Director, Regulatory Services

Attachments

cc: Tolls Task Force (on-line notification)
Mainline Customers (on-line notification)

Tolls Task Force

2008 TOLLS TASK FORCE ISSUE	
Date Accepted As Issue: September 4, 2008	**Resolution:** 04.2009
Date Issue Originated: September 4, 2008	**Sheet Number:** 1 of 3
Issue Originated By:	Shell Energy North America (Canada) Inc.
Individual to Contact: Tomasz Lange	**Telephone Number** (403) 216-3580

ISSUE: FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature

RESOLUTION:

The TTF agrees to the addition of the current FT - Risk Alleviation Mechanism (FT-RAM), STS-RAM and STSL-RAM pilots, to the TransCanada tariff as permanent features of the transport services effective November 1, 2009 as per the attached black lined IT Toll Schedule.

BACKGROUND:

On May 6, 2004 the TTF approved, as an unopposed resolution, the initial FT-RAM pilot (Resolution 02.2004) for a one-year period beginning November 1, 2004. The initial pilot program was adopted as a flexibility feature of long-haul FT contracts only. Long-haul FT contracts are those contracts, which have a primary receipt point originating from Empress or Saskatchewan.

On August 3, 2005 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional one-year term commencing November 1, 2005 and ending October 31, 2006 (Resolution 20.2005).

On February 24, 2006 the NEB approved an application by Coral Energy Canada (now Shell Energy North America (Canada) Inc.) for modifications to the FT-RAM pilot effective April 1, 2006 and ending October 31, 2006, to extend FT-RAM credits to short-haul contracts, which when combined with a long-haul contract create a continuous long-haul contract (Board Order TG-1-2006 in RHW-2-2005 proceeding).

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The short-haul and long-haul contracts must be held by the same shipper and must share a common location; i.e. the receipt point of the short-haul contract must be the same as the delivery point of the long-haul contract. For example, a Dawn to EDA short-haul contract when combined with a long-haul contract from Empress or Saskatchewan to SWDA if held by the same shipper, effectively results in a long-haul contract to EDA. In keeping with the intent of the FT-RAM Pilot of encouraging firm long-haul contracts, FT-RAM credits will be granted on the full path or both contracts.

On April 5, 2006 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot, as modified by the NEB in the RHW-2-2005 decision, for an additional one-year period commencing November 1, 2006 and ending October 31, 2007 (Resolution 05.2006).

On February 9, 2007 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 03.2007)

Also on February 9, 2007 the TTF approved, as an unopposed resolution, a new RAM pilot for Storage Transportation Service and Storage Transportation Service Linked (STS-RAM and STSL-RAM) for a two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 02.2007). On July 4, 2007 the TTF approved, as an unopposed resolution, tariff language for the STS-RAM and STSL-RAM pilot (Resolution 08.2007). STS service was originally designed to work in combination with LDC held long-haul FT service on TransCanada and with market storage. It was designed to allow LDCs to meet seasonal and daily fluctuations in market demand while maintaining their long-haul service at a high load factor. STS shipper must hold long-haul FT. The flow of gas and the capacity rights are virtually identical under STS and STSL. The only difference is that under STS, the long-haul contract is held by the LDC, whereas under STSL, the end-users and marketers hold the long-haul contract.

RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada Mainline. The motivation behind RAM is to promote the renewal of and incremental contracting for long-haul FT service. During the various pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users. The mechanism will not limit the service entitlements of current FT service.

VOTING RESULTS:

Unopposed resolution at the January 7, 2009 TTF meeting in Calgary.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref:

What is Union's forecast of inflation for the years 2012, 2013, 2014, 2015, 2016, 2017, and 2018, relative to the years 2012 over 2011 for the all in "CPI", and the "all in" OPI?

Response:

Union assumes a 2% annual inflation rate for both Canada and Ontario for the 2012 to 2014 period.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref:

Please provide a schedule showing the impact on earnings and revenue requirement of Union's past participation in TCPL's FT RAM program, for each of the IRM years, including 2012.

Response:

Please see the response at Exhibit J.C-4-7-9, Attachment 1.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Exhibit A2, Tab 1, Schedule 1, Page 25, Table 5

Please explain what incremental revenue was realized in 2008, 2009, 2010, and 2011 through the use of FT RAM credits. How much of the revenue shown on line 3 is due to FT RAM? Will that revenue reoccur in 2012?

Response:

Please see the response at Exhibit J.C-4-7-9, Attachment 1, line 1.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 25

Union projects sustainable O&M productivity gains of $22.5 million in 2013, consisting of $15.9 million of gains persisting from savings taken up to and including 2011, and incremental productivity gains realized in 2012 of $6.6 million which will persist into 2013.

a) i) Please describe in detail each category of the $15.5 million of persisting O&M productivity gains of $15.9 million and the 1.1, 1.9, 9.7, and 10.8 of capital productivity gain in years 2008 through 2011, respectively. Please describe the difference between O&M productivity gain and capital productivity gain. Please include examples of each. ii) What incremental O&M and capital productivity gains, if any, were achieved in 2012.

b) What explains the increase in persisting total productivity gain from 15.5 to 15.9? Is the additional 0.4 million capital productivity gain?

c) Why do more of the capital productivity gains for 2011 and previous years not persist into 2012 and 2013?

d) Will the entire 22.9 in 2013 productivity gain persist through the years 2014, 2015, 2016, 2017, and 2018? If any parts of it will not, what parts, and why?

Response:

a)

i. The evidence found in Exhibit A2, Tab 5 and Exhibit A2, Tab 5, Appendix A provide detailed information regarding O&M and Capital productivity cost savings. Cumulative O&M productivity savings ("gains") are related to savings realized in O&M expenditures. Cumulative capital productivity savings ("gains") are related to savings from capital expenditures. Examples of each can be found in these Exhibits.

ii. Please see the response at Exhibit J.O-4-1-9.

b) The $15.9 million referred to in Exhibit A2, Tab 1, Schedule 1, page 25, line 5 should be $15.5 million.

c) The capital productivity gains indicated in Exhibit A2, Tab 5 are influenced by two large initiatives whose savings vary on an annual basis. The two initiatives influencing these trends are "Construction, Planning, Reporting & Execution Process" and "Major Projects Design

Work". Savings from these initiatives are a function of both the number of projects in progress and the size of the effort from which the savings can be realized. In order to recognize the savings for these initiatives, each year, a new pool of projects must be identified from which productivity savings can be realized. This is explained in more detail in Exhibit A2, Tab 5, Appendix A, pages 8-10.

d) Yes.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit D1, Tab 7, page 4

Union's evidence indicates that it does not have a Treasury function. Union purchases treasury services from Spectra. Spectra's Treasury system is being modified and Union will bear a portion of the depreciation expense beginning in 2012.

a) Please explain why a Treasury function would have a depreciation component.

b) What is the forecasted depreciation expense for 2012 and 2013 that Union will have to bear?

Response:

a) The depreciation expense relates to the capital cost incurred by Spectra to implement new treasury software.

b) Union's annual depreciation expense for 2012 and 2013 related to the Treasury software is approximately $0.042 million. Union is allocated 16.4% of the Treasury IT system ($0.416 million of the $2.5 million cost). The allocation to each BU is based on the number of bank accounts and treasury deals managed by Treasury. The $0.416 million will be amortized equally over 10 years.

UNION GAS LIMITED

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

Ref: Exhibit A1, Tab 10

a) For each of the employees on the utility organization charts that are shown as not a Union Gas employee, please provide the amount of cost that are included in the requested revenue requirement for 2013, the forecast for 2012 and the actual expense for 2010 and 2011.

b) For each employee shown as not a Union Gas employee, please provide the total compensation paid to the employee broken down by component (for example salaries, incentives, benefits, etc.) and show the amount of each component that has been allocated to Union Gas for recovery from ratepayers for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain any changes made in the allocation methodology between 2010 and 2013.

c) For each employee shown as not a Union Gas employee, please indicate what company or companies they are employees of.

d) Do any of the positions that report to the VP Bus Dvlpt Stor Trans shown on pages 2 & 3 do work related to companies other than Union Gas? If yes, please provide the allocation of the total compensation for all the positions reporting to the vice president between Union Gas and any other affiliates for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain how the allocation has been determined and any changes that have been made between 2010 and 2013.

e) Do any of the positions that report to the Mgr Underground Storage Canada shown on page 2 do work related to companies other than Union Gas? If yes, please provide the allocation of the total compensation for all the positions reporting to the manager between Union Gas and any other affiliates for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain how the allocation has been determined and any changes that have been made between 2010 and 2013.

f) Do any of the positions that report to the Manager Commodity Tax and/or Manager Research and Planning shown on page 12 do work related to companies other than Union Gas? If yes, please provide the allocation of the total compensation for all the positions reporting to the these positions between Union Gas and any other affiliates for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain how the allocation has been determined and any changes that have been made between 2010 and 2013.

g) Do any of the positions that report to the VP Finance shown on pages 11 - 13 do work related to companies other than Union Gas? If yes, please provide the allocation of the total compensation for all the positions reporting to the vice president between Union Gas and any other affiliates for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain how the allocation has been determined and any changes that have been made between 2010 and 2013.

h) Do any of the positions that report to the VP Human Resources Canada shown on page 14 do work related to companies other than Union Gas? If yes, please provide the allocation of the total compensation for all the positions reporting to the vice president between Union Gas and any other affiliates for 2013, the forecast for 2012 and the actual expense for 2010 and 2011. Please explain how the allocation has been determined and any changes that have been made between 2010 and 2013.

Response:

a) & b) The table below provides the total compensation for those employees listed in Table 1 under part (c) of this response that is included in Union's cost of service. The roles in Table 2 do not work for Union, however they do provide services under a SLA. These costs are included in the affiliate expenses. Allocations are done at a department or function level, not at the employee level. Attachment 1 shows the allocations for the areas affected.

Line No.	Particular ($000's)	2010 Actual (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)
1	Salary & Wages	756	995	1,044	1,080
2	Benefits	229	201	211	218
3	Incentives	749	1,122	502	509
4	Total	1,734	2,318	1,757	1,807

c)

Table 1

Role	Employer
President	Spectra
VP Business Development Storage Transmission	Spectra
VP Finance	Spectra
Mgr Underground Storage Canada	Westcoast

Table 2

Role	Employer
VP Human Resources Canada	Westcoast
Mgr Commodity Tax	Westcoast
Mgr Research and Planning	Westcoast

d) The charges to affiliates from within the area of the VP Business Development Storage and Transportation are service specific and are either fully allocated costs ("FAC") or the greater of FAC and market prices as required by the ARC. Depending on the service, the charge will be either an hourly rate for the hours worked or a monthly fee based on estimated time. Hourly rates are used where Union and the affiliate cannot estimate requirements.

e) The Manager Underground Storage Canada reports to the VP Business Development Storage and Transportation. There are no changes to the allocation methodology between 2010 and 2013.

f) The Tax department costs are a pooled resource between Union, SET-West and Spectra. The cross billing of charges uses fully allocated costs. Each of Union, SET-West and Spectra determine time allocations and cross bill at 1/12 of the annual fee. There are no changes to the allocation methodology between 2010 and 2013.

g) The Finance department provides services for Accounts Payable ("AP"), Affiliate Accounting & Reporting and Pension accounting. Charges are fully allocated costs using time factors. The allocation methodologies have not changed except for Accounts Payable. In 2011 and prior years the AP department was allocated based solely on number of payment vouchers. As of January 2012, a direct assignment of staff is allocated to each of Union, Spectra and Set-West. The assignment matches the number of staff assigned to each AP service for each company.

h) The HR organization is a combination of pooled resources and company specific functions. Union, Spectra and SET-West cross bill using fully allocated costs. The allocator is headcount after direct assignment of costs where applicable. The VP of HR who is located in Vancouver, is responsible for the entire Canadian HR function, and their costs are within the Westcoast organization. There are no changes to the allocation methodology between 2010 and 2013.

Percent of Function charged to Affiliates

Line No.	Role	Functions with Area that Work for Affiliates	2010 (a)	2011 (b)	2012 (c)
1	VP Business Development	Underground Storage--Note 1			
2		Gas Mgmt Services	3%	3%	3%
3		Gas Control &Capacity Planning	3%	4%	3%
4		Business Development--Note 2		44%	59%
5		Gas Supply--Note 1			
6	General Manager Tax	Tax	50%	50%	50%
7	VP Finance	Pension Accounting	52%	52%	64%
8		Plant Acct'g & Affiliate Reporting	12%	11%	11%
9		Accounts Payable	41%	41%	64%
10	VP HR	HR Services	42%	42%	43%
11		Benefits	27%	27%	27%
12		Compensation	42%	42%	42%
13		Employee Relations	2%	2%	2%
14		Workforce Planning	47%	47%	47%
15		Development & Performance	40%	40%	40%

Notes
1. The % relative to the department total is less than 1%.
2. Prior to 2011 the staff managing affiliates (e.g. Market Hub Partners) were not employed by Union.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 7, Updated

a) Please provide the depreciation study used to set the depreciation rates for line items 5 through 8 in Table 2. Please indicate when this depreciation study was last updated.

b) Have the depreciation rates used to arrive at the depreciation expenses shown in lines 5 through 8 in Table 2 been approved in any regulatory jurisdiction that Spectra operates? If yes, please provide details.

Response:

a) The charges in the table represent Union's share of Spectra's amortization expense for the SAP project. They are not the subject of a depreciation study.

b) No.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 7

The 2012 and 2013 forecasts are based on 2011 Service Level Agreements ("SLA") plus inflation, plus/minus known changes for specific SLAs.

a) Provide an update to the SLAs for 2013 services, either the 2012 SLAs plus material changes or the same based on 2011 for 2012/2013.

b) When are SLAs for the forward rate (or test year) updated? When will 2013 SLAs be available and are they filed with the Board?

Response:

a) Union is not filing an update to the 2013 test year forecast.

b) The 2013 SLAs will not be finalized until the end of the first quarter in 2013. They will not be filed with the Board.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Page 15 &
Exhibit D1, Tab 7, Table 2, Line 6

a) Explain the increase in affiliate HR costs over 2012-2013.

b) If this is due in part, to sourcing SAP payroll services from Spectra, provide details of how the total costs are allocated across Spectra companies:
   - total cost across Spectra,
   - total and % of cost allocated to Union Gas, and
   - allocation methodology (cost drivers etc).

Response:

a) The increase in the affiliate HR costs between 2012 and 2013 is the result of including six months of amortized depreciation in 2012, totalling $0.511 million and twelve months in 2013, totalling $1.024 million. The 6 month period for 2012 recognizes the system becoming available July 1, 2012.

b) Please see the response at Exhibit J.D-1-2-7 for a description of the charges, percent allocated to Union and the allocation methodology.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 7, page 2

With respect to Affiliate Services there is a net revenue increase from 2010 to 2013 of $3.5 million. Please explain the reason for that variance.

Response:

The breakdown of affiliate revenue from 2010 to 2013 is found at Exhibit D1, Tab 7, Schedule 2. The primary drivers of the $3.5 million increase in affiliate revenue are the recovery of IT Enterprise Project services of $1.4 million; Finance AP services of $0.9 million and Government Relations services of $0.7 million.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 7, page 7

For all of the services for which Union is a "receiver only" Please provide a schedule setting out budgets for each item (Corporate Services, ECS, Ethics, Finance etc.) for the years 2011-2013. Please provide evidence demonstrating that it is more cost-effective to procure those services from its affiliates than from other sources.

Response:

The services Union receives from affiliates are not available from other sources. The services make use of common management of a function, common processes, policies, and systems that the Spectra organization uses and which Union benefits from. Reproducing the staffing within Union would not be cost effective as Union would need to hire additional full time roles that would cost well in excess of the partial allocation of roles included in the SLA costing from Spectra.

The table below identifies the number of FTE's in the source department and the number and the percent allocated to Union. The table and costing approach only identifies source department roles that support shared services.

As shown in line 18 of the table, Union is allocated approximately 13% of the 71 roles that provide services. Replicating the roles within Union or from another source would not be cost effective.

Within the table, the salary and wages ("S&W") component of the roles providing shared services represents the "budget" of the source departments. The SLA fee is S&W plus the indirect cost factor which is applied to S&W for a fully loaded cost.

The 2013 forecast was based on 2011 SLAs.

All figures in $000's USF

			2010						
			Provider		Union Allocation				
Line	Company	Service	S&W	FTE	S&W	FTE	% of S&W	% of FTE's	
1	Spectra	ECS	$ 2,978	13	$ 248	1.8	8.3%	14%	
2	Spectra	Ethics	$ 311	3	$ 91	0.9	29.2%	29%	
3	Spectra	Corporate Services	$ 681	6	$ 28	0.3	4.1%	5%	
4	Spectra	Finance	$ 4,015	41	$ 586	6.2	14.6%	15%	
5	Spectra	S&T Marketing	$ 739	7	$ 93	0.8	12.6%	11%	
6									
7		Total	$ 8,724	70	$ 1,046	9.9	12.0%	14%	
8									
9			**2011**						
10			Provider		Union Allocation				
11	Company	Service	S&W	FTE	S&W	FTE	% of S&W	% of FTE's	
12	Spectra	ECS	$ 2,411	13	$ 204	1.5	8.5%	12%	
13	Spectra	Ethics	$ 382	4	$ 107	1.1	28.1%	28%	
14	Spectra	Corporate Services	$ 694	6	$ 32	0.3	4.7%	5%	
15	Spectra	Finance	$ 4,054	41	$ 590	5.7	14.6%	14%	
16	Spectra	S&T Marketing	$ 726	7	$ 96	0.8	13.2%	11%	
17									
18		Total	$ 8,267	71	$ 1,030	9.4	12.5%	13%	

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 7

Please explain what services are provided to Union under the heading "Ethics".

Response:

The Ethics and Compliance Services SLA includes:

Ethics and Compliance Services

- The Spectra Energy Ethics and Compliance Department has day-to-day responsibility for enterprise-wide ethics and compliance issues. This day-to-day responsibility requires that specific individuals report notable compliance issues up the chain of command to the governing authority. Day-to-day responsibilities also include the Ethics and Compliance Department ensuring the adequacy of compliance and system controls, monitoring the effectiveness of the program, Code of Business Ethics training and the questionnaire, and administering the EthicsLine. In addition, the CCO and VP of the Ethics and Compliance Department have periodic meetings with the compliance managers of the Functional Units—Human Resources, Information Technology, Pipeline Integrity Group (Department of Transportation), Environmental Health and Safety, Legal, Regulatory, and Audit Services.

- Services include:
  - Communication and Training
  - Monitoring and Auditing, Evaluating Effectiveness and Publicizing Reporting System
  - Consistent Enforcement
  - Assessment if Criminal Conduct has Been Detected
  - Risk Assessment

UNION GAS LIMITED

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

Ref: General

a) Please provide a list of all financial transactions between Union with its affiliates – that are not listed elsewhere in the pre-filed evidence – for each year 2008-11, and projected for 2012 and 2013.

b) Please provide generic descriptions of each type of transaction listed in the previous part along with a rationale as to why said transaction was in the interest of Union's ratepayers.

Response:

(a), (b) Please see Attachment 1.

The tables in Attachment 1 show payments made by Union and payments received by Union. The tables exclude the following: SLA fees, LTIP payments, loan and interest payments, gas, transportation and storage payments, dividends.

Payments made and received are mostly reimbursements of 3rd party invoices paid by one company that are attributable to one or more other companies. The reference to Project Cost in each of the two tables is reimbursement of internal and 3rd party costs for work on common projects.

The types of transactions shown in the payment table are typical payments Union would have made in the ordinary course of business to a 3rd party had the vendor billed Union directly for its share. These are not services from an affiliate. For example, under software, Microsoft bills Spectra for the entire Spectra organization. Union in turn reimburses Spectra its share (at cost and without markup).

Line No.	Payments made by Union $000's ($000's)				
	Type	2008	2009	2010	2011
1	Software	575	825	671	928
2	Training	22	138	548	105
3	Association Fees	34	36	-	80
4	Consulting	541	28	193	229
5	Project Cost	133	14	276	20
7	SEDAR	140	123	82	52
8	Bank Fees	3	4	2	1
9	Other	235	119	16	56
10	Total	1,681	1,289	1,788	1,470

Line No.	Payments received by Union $000's ($000's)				
	Type	2008	2009	2010	2011
1	Software	420	567	329	247
2	Training	-	6	94	297
3	Association	-	1	3	3
4	Consulting	77	45	69	- 8
5	Project Costs	169	3	97	696
6	Misc Other	9	32	-	17
7	Total	676	654	592	1,253

UNION GAS LIMITED

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

Ref: A1 T9

a) Are the interest rates on Inter-Company Loans the same for lending as for borrowing? Please provide these rates if different and indicate how the interest rate is determined.

b) Are all costs under Gas and Storage purchases for gas purchase? If not, please provide a breakdown of these costs.

c) If applicable, please provide a similar breakdown for upstream transportation costs.

Response:

a) Yes, the interest rates on Inter-Company Loans are the same for lending as for borrowing.

b) No, the costs under Gas and Storage Purchases are not just gas purchases. Please see Attachment 1 for a breakout of Gas Purchases and Storage Purchases.

c) N/A – St. Clair Pipelines is included in Attachment 1.

UNION GAS LIMITED
Affiliate Transactions

B. COSTS

	2010 ($)	2011 ($)
1. Gas Purchases		
Westcoast - Empress	3,739,035	49,143,553
Total	$ 3,739,035	$ 49,143,553
(Note: Gas purchases made using Union's tendering		
2. Storage Purchases		
Market Hub Partners	1,783,500	1,783,500
Sarnia Airport Pool L.P.	4,830,614	4,525,785
Huron Tipperary Limited Partnership	643,740	586,927
Total	7,257,854	6,896,212
3. Upstream Transportation (1)		
St. Clair Pipelines LP (Bluewater Pipeline)	$ 629,628	$ 629,628
St. Clair Pipelines LP (St. Clair River Crossing)	342,000	342,000
Total	$ 971,628	$ 971,628
(Note: Service purchased by Union as per NEB		

Note:

(1) Contracts are ongoing. The Bluewater Pipeline charges under the Second Amendment to the Transportation Services Agreement between St. Clair Pipelines (1996) Ltd. and Union Gas Limited dated November 1, 1995. The charges for the St. Clair River Crossing under Terms of Agreement between St. Clair Pipelines Limited and Union Gas Limited dated May 1, 1988.

* Includes Dec 31 year-to-date information.

UNION GAS LIMITED

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

Ref: Exhibit A1, Tab 11, Schedule 1

Please provide a list of all of the entities (whether corporations or otherwise) listed on the Corporate Organization Chart that are affiliates of the Applicant for the purpose of the undertakings.

Response:

An affiliate for the purpose of the undertakings has the same meaning as the Business Corporation Act, all entities in which Spectra has greater than a 50% of the voting control. Union treats 50% entities as affiliates for ARC purposes.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 6, Appendix A

a) Do the figures shown in the table in Appendix A reflect both the regulated and unregulated assets of Union Gas?

b) If the response to the part (a) above indicates that the figures reflect both regulated and unregulated assets, please provide a revised Appendix A that reflects only the regulated assets of Union Gas that are included in rate base.

Response:

a) The figures in Appendix A reflect only the regulated assets of Union.

b) Appendix A reflects only the regulated assets of Union.

UNION GAS LIMITED

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

Ref: Exhibit D2

a) Please provide a summary of the changes that result in the increase in the depreciation rate from 10.07% to 13.27% for 48400 Transportation Equipment as shown on page 17.

b) Please provide a summary of the changes that result in the increase in the depreciation rate from 4.55% to 6.92% for 48500 Heavy Work Equipment.

c) What is the impact on the depreciation expense and on the revenue requirement (including the change in rate base) if 48320 Office Equipment - Computers was amortized over 3 years rather than 4.

Response:

a) The change in the depreciation rate for Account 48400 (Transportation Equipment) to 13.27% from 10.07% is largely attributable to a reduction in the estimated future salvage for this account. The historical net salvage analysis indicates a steady decline in salvage realized from the sale of used vehicles. The ratio of realized salvage to retirements was 12.2% over the past 10 years and 8.2% over the most recent 5 years. Based on these observations and an expectation that realized salvage will not likely increase in the foreseeable future, the recommended salvage rate has been reduced to 10% from the previously estimated 30%.

b) The change in the depreciation rate for Account 48500 (Heavy Work Equipment) to 6.92% from 4.55% is largely attributable to a reduction in the estimated future salvage for this account. The historical net salvage analysis indicates a steady decline in salvage realized from the sale of used equipment. The ratio of realized salvage to retirements was 7.3% over the past 10 years and 0.1% over the most recent 5 years. Based on these observations and an expectation of negligible salvage in the foreseeable future, the recommend salvage rate has been reduced to 0% from the previously estimated 30%.

c)

Depreciation Expense	Increase $2.0 million
Rate Base	Decrease $6.1 million
Revenue Requirement	Increase $1.7 million

There is also a one-time $10 million transitional impact that would need to be recovered in rates. This amount has not been reflected in depreciation expense, but has been included in the reduction of rate base.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 2, Schedule 2, Updated

a) Does Union have any explanation for the high volume of UFG in 2009 relative to 2010 and 2011 even though the actual throughput in 2009 was lower than in 2010 and 2011?

b) Please update the cost of the estimated UFG to reflect the most recent QRAM reference price available.

Response:

a) Union does not have an explanation for the favourable trend of UFG for 2010 and 2011.

UFG arises for a number of reasons, some of which are not under the control of the utility. Where under the control of the utility, Union makes every effort to mitigate the impact. UFG can arise from undetected gas leaks on the system, estimation errors in recording gas releases during maintenance, and theft of gas. However, it is generally accepted that the most significant cause of UFG is measurement variation. This is the variance that arises between the measurement at the input to the Union system and at the customer meters.

Gas measurement devices are not 100% accurate. These devices measure gas volumes within an allowable range as regulated by Industry Canada because of factors, which affect measurement such as temperature, pressure, altitude above sea level, and the flow rate of gas. The allowable accuracy for gas meters is approximately 2%.

b)

Line No.	Particulars	
1	Estimated UFG volume for 2013 (10^3m^3) (1)	70,253
2	EB-2012-0070 reference price ($\$/10^3m^3$)	176.43
3	Estimated UFG for 2013 ($000's) (2)	12,395

Notes:
(1) Exhibit D3, Tab 2, Schedule 2, Line 11, Updated.
(2) Line 1 * Line 2/1,000.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 2, Schedules 1 & 2, Updated

a) Please reconcile the estimated UFG cost shown on Schedule 2 of $14,234 with the UFG adjustment shown on line 10 of Schedule 1, page 2.

b) Please reconcile the unregulated allocation for short-term and long-term figures of (358) and (1,001) shown on Schedule 2 with the unregulated costs of (2,252) shown on line 13 of Schedule 1, page 2.

Response:

a) The variance between Exhibit D3, Tab 2, Schedules 1 and 2, Updated is due to a difference in presentation and the timing of the preparation of the two schedules. The estimate for UFG is based on the most recent three years of actual data. The 2013 UFG estimate is based on actual data from 2009 through 2011.

   Schedule 1, was created using preliminary estimates for throughput and UFG ratio. $21.905 million of estimated UFG is included as a component of the Total Supply (Exhibit D3, Tab 2, Schedule 1, Page 2, Line 1, Updated).

   When the estimated UFG volume was updated to incorporate the 2011 actual data and the final estimate for throughput, an adjustment to the Gas Purchase Expense of $7.671 million was required and shown separately on Line 10.

   In Schedule 1, UFG is presented in two lines whereas in Schedule 2, it is shown on one line.

However, both schedules include $14.234 million for the UFG estimate.

Line No.		($000's)
1	Estimate used in the Gas Supply Plan (1)	21,905
2	Adjustment to Gas Supply Plan (2)	(7,671)
3	Total UFG estimate per Schedule 1	14,234
4	Total UFG estimate per Schedule 2 (3)	14,234

Notes:

(1) Exhibit D3, Tab 2, Schedule 1, Page 2, Part of Line 1, Updated.
(2) Exhibit D3, Tab 2, Schedule 1, Page 2, Line 10, Updated.
(3) Exhibit D3, Tab 2, Schedule 2, Line 12, Updated.

b) Exhibit D3, Tab 2, Schedule 1, Updated includes unregulated UFG, Compressor Fuel, Customer Supplied Fuel and third party storage. Exhibit D3, Tab 2, Schedule 2 is UFG only.

Line No.	Particulars ($000's)	Schedule 1	Schedule 2
1	Short Term UFG	358	358
2	Long Term UFG	1,001	1,001
3	Compressor Fuel	3,903	-
4	Customer Supplied Fuel	(3,190)	-
5	3rd Party Storage	180	-
6		2,252	1,359

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D3, Tab 2 Schedule2,

Please explain the high volume of UFG in 2009 relative to 2010 and 2011.

Response:

Please see the response at Exhibit J.D-5-2-1 a).

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 8

a) The evidence at the bottom of page 1 indicates that the forecast expense is consistent with historical investment levels. Did the revenue required approved by the Board in setting 2007 rates include any costs related to community investments? If so, please quantify.

b) Are any of the community investment expenses (actual and/or forecast) eligible as income tax deductions? If yes, please explain and indicate whether or not an adjustment has been made to the 2013 income tax calculation.

c) If the community investments enhance Union's reputation, to the benefit of the shareholder, please explain why the shareholder should not bear these costs.

Response:

a) Community investment expenditures were not included in the 2007 Board-approved revenue requirement.

b) The community investment expenses are eligible deductions for tax purposes. The tax savings associated with these deductions have been incorporated into the 2013 forecast.

c) Union is proposing to recover expenditures associated with community investment because they provide tangible and verifiable benefits to ratepayers and their communities, and as such, should properly be recovered from ratepayers. As indicated at Exhibit D1, Tab 8, page 2, community investment expenditures enhance the overall economic health of the community, provide opportunities to influence customer behaviour in the areas of conservation and health and safety, and enhance Union's ability to manage the risks and costs associated with its distribution, transmission and storage business.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 8

a) Provide Community investment funding history 2007-2011 and projection 2012/2013.

b) How much has the shareholder invested in community projects over the same period?

Response:

a) 2007 = $207,170
2008 = $195,820
2009 = $192,000
2010 = $277,290
2011 = $538,800 ($300,000 is a one-time spend for the Centennial Celebrations)

Projected spend for 2012 is $374,000 and for 2013 is $374,000

b) In addition to the amounts referenced above, Union and Spectra have contributed the following:

Year	United Way Matching Grants	Regular Matching Grants	Volunteer Grants	Total
2007	$347,147	$ 54,697	$140,179	$542,023
2008	$208,476	$ 47,972	$139,885	$396,333
2009	$305,091	$ 45,065	$ 89,748	$439,904
2010	$380,796	$148,886	$103,325	$633,007
2011	$376,720	$147,954	$129,083	$653,757

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 8

How was the $374,000 Community Investment Fund budget derived? Please indicate what projects are planned for 2013. What has been the annual budget for the period 2007-2012? Please explain why these expenditures are not more appropriately characterized as charitable donations. Will Union receive any taxable benefits for these expenditures?

Response:

The community investment budget of $374,000 is based on historical budget allocations from Spectra Energy. Annually Spectra Energy has allocated funds to each of its businesses units earmarked for community investment initiatives.

Community investment projects for 2013 have not been determined. The planning process for 2013 community investment projects will begin in the summer of 2012. For instance, between 2007 and 2011 Spectra Energy gave $269,850 to seven Safety Villages across Ontario. In 2012, projects include:

Safety:
- City of Hamilton - Emergency Fire Services - Fire Prevention Division - $2,500
- Oliver Paipoonge Fire & Emergency Services - $1,500
- London Fire Department Safety Initiatives - $2,500
- The City of Temiskaming Shores - Temiskaming Shores Fire Department - $1,000
- Coleman Volunteer Fire Department - $1,000

Conservation:
- Lower Thames Valley Conservation Authority - $10,000
- Halton Region Conservation Foundation - $2,500
- The North Bay-Mattawa Conservation Authority - $1,500
- St. Clair Region Conservation Authority - $5,000

Leadership Support:
- Leadership Thunder Bay - $5,000
- Dryden Volunteer Recruitment and Referral Centre (Leadership Dryden) - $2,500

Junior Achievement:
- Junior Achievement of South Western Ontario - $9,000

For community investment spending for the 2007 through 2011, please see Exhibit J.D-6-3-1. The community investment budget for 2012 is $374,400.

Community Investment are activities that Union undertakes to help the communities it serves address economic, social and environmental challenges above and beyond creating wealth for shareholders, creating jobs and paying taxes.

The community investment expenses are eligible deductions for tax purposes. The tax savings associated with these deductions have been incorporated into the 2013 forecast.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit D1, Summary Schedule 2
Exhibit D1, Tab 8

Please provide details of Union's community investments in the 5-years prior to the 2007 Base Year and advise whether these investments were or were not included in Union's utility Cost of Service. If such investments were not previously included in the Cost of Service, then please provide the rationale for that approach.

Response:

The community investment expenditures for 2002 to 2006 are provided below.

2002 - $207,500
2003 - $247,537
2004 - $93,030
2005 - $112,745
2006 - $212,427

Community investment expenditures have not historically been included in Union's revenue requirement for recovery from ratepayers.

There is no rationale as to why community investment expenditures have not been part of Union's revenue requirement in the past. Union is now proposing to recover community investment expenditures because they directly benefit ratepayers and, therefore, are properly recovered from ratepayers.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 10

Union's proposed 2013 O&M budget includes $5.0 million related to the Energy Technology Innovation Canada ("ETIC") program. Union states that the initial focus of ETIC is to facilitate and drive natural gas technology innovation that ensures natural gas remains a preferred foundational fuel.

a) Please provide the adverse impacts to ratepayers if Union does not undertake the ETIC program.

b) Union has budgeted an amount of $5.0 million that is consistent with the average level of R&D investment for the six primarily natural gas utilities included in the 2011 EU scorecard. Does Union have any information on whether activities undertaken by the above six natural gas utilities have spurred innovation or led to the development of new or advanced technologies within the natural gas sector? Please provide details.

c) Has Union considered sharing financial resources or partnering with other utilities and agencies to collaborate on innovation or development of new technology within the natural gas sector. Please provide a detailed response on the collaborative efforts undertaken or will be undertaken in the future.

Response:

a) The rationale for Union's participation in ETIC is provided at page 3 and 4 of Exhibit D1, Tab 10. As indicated, specific adverse impacts if Union does not participate include:

- Inability to support and inform customers regarding leading-edge high efficiency products and systems such as gas-fired heat pumps and hybrid equipment;
- Inability to influence new technology designs to the advantage of Union's customers such as micro-cogeneration and district energy technologies;
- Inability to advocate for, support and demonstrate new gas technologies and systems of benefit to our customers such as natural gas based smart network technologies.

b) A summary of the research results from each of the six natural gas utilities referenced in Table 1 is shown below. More information on details of specific projects they have completed or are currently undertaking is provided through the links provided to each of their websites.

GDF Suez – Research and innovation programs include:

- Renewable Energies
- CO2 Capture and Storage
- LNG
- City and Building of Tomorrow
- Smart Energy and Environment

Further information on their approach to innovation can be found at:
http://www.gdfsuez.com/en/activities/research-innovation/research-and-innovation/

RWE – Current Technology innovation programs include:

- Energy House of the Future
- Smart Meter
- Power Matching City
- Distributed Generation

Further information on their approach to innovation can be found at:
http://www.rwe.com/web/cms/en/184336/rwe/innovations/

E.ON – Current areas of technology innovations spending include a broad range of energy technologies. A link to E.ON's Innovation For Energy program describing the focus of their research since 2007 can be found at: http://www.eon.com/content/dam/eon-com/en/downloads/i/IRI_guide_2012.pdf

National Grid - The primary area of technology innovation spending is focused on smart grid technologies.

Osaka Gas- Specific end use technology innovations developed include:

- High sensitivity household methane detectors
- Low NOX gas turbine combustors
- Micro CHP systems
- Adsorptive biogas storage systems

A more complete listing of technology innovations can be found at:http://www.osakagas.co.jp/rd/indexe.html

Tokyo Gas – Specific end use technology innovations developed include:

- Commercial kitchen appliances
- Ultrasonic gas meters
- Smart Energy grid applications
- Solid Oxide fuel Cells

A more complete listing of technology innovations can be found at:

http://www.tokyo-gas.co.jp/techno/index_e.html

Each of the four European primarily natural gas entities referenced above are also active members of GERG, the European Gas research Group. GERG's stated mandate is:

To encourage and support the development of high quality R&D projects and assists in the development of a sound framework for European gas research by:

- *providing the appropriate forum for discussion, technological exchange and dissemination.*
- *identifying the key issues in each major sector of the gas business.*
- *ensuring that relevant topics are adequately covered by R&D.*
- *maximising the value of such research carried out in Europe and the use of specialist facilities.*
- *avoiding wasteful duplication of effort.*
- *identifying appropriate funding mechanisms*

GERG is a European based entity that is aligned with the ETIC concept. Its portfolio of projects has varied between 5 million and 38 million euros over the past 10 years.

c) ETIC was formed to allow natural gas sector participants to share resources and collaborate on innovation and technology development.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 10

a) Please provide the actual 2011 ETIC expenditure.

b) Please provide most recent estimate of the ETIC expenditure that will take place in 2012.

c) Please provide a list of the current ETIC projects being considered for evaluation.

d) Please comment on the overlap of ETIC funding for any DSM related projects such as high efficiency water heaters with DSM expenditures.

Response:

a) Please see the response at Exhibit J.D-7-5-1.

b) Please see the response at Exhibit J.D-7-5-1.

c) Please see the response at Exhibit J.D-7-5-1.

d) Any DSM research related projects that Union participates in will be funded by Union's DSM research budget, although the projects may be coordinated through ETIC. All other ETIC projects that Union participates in will be funded through the specific ETIC budget. As a result, there will be no funding overlap as each project will be funded by either the ETIC budget or the DSM research budget.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 10, Pages 1 –7

In 2011, 2012 and 2013, Union is projecting expenditures of $0.6 million, $3.0 million and $5.0 million respectively, related to the ETIC program.

a) Is participation in ETIC voluntary to GGA members?

b) What is the basis of CGA Funding? Is it Formula Based and what is the formula/allocation for Union?

c) Please provide copy of CGA- ETIC Agreement and funding Commitment(s).

d) How many Gas Utilities are funding the CGA- ETIC program? Please provide list and numbers. Position Union's Commitment in context.

e) What are the current ETIC Projects? Provide the 2011 -2012 portfolio summary and costs and delineate Union's share of funding for each project.

f) What other R&D is Union Funding from Rates-Internal and External e.g. GRI? Provide a summary list and costs- 2011 actual and projected 2012/2013.

Response:

a) Yes.

b) The financial contributions of participating CGA member companies is based on a fee formula. Union's 2012 CGA membership allocation is $0.474 million.

c) Since ETIC is a project of the CGA, dues for ETIC are paid to CGA and held in trust for use on ETIC. The financial commitment from the members for ETIC's operating budget is $0.350 million per year (for each of 2011, 2012 and 2013 after which time it will be reviewed).

d) The CGA member companies who are financial contributors to ETIC are the following:

Fortis BC
ATCO Gas
Alta Gas
SaskEnergy
Manitoba Hydro
Union Gas
Enbridge Gas Distribution
Gaz Metro

Union's commitment to ETIC's annual $350,000 operating budget is $69,650.

e) Please see the response at Exhibit J.D-7-5-1.

f) Union's technology related research budget includes the following three components: Utilization Technology (transitioning to ETIC) - 2011 Actual - $871,578, 2012 Budget - $2,549,201

DSM Research – 2011 Actual $602,547, 2012 Budget $776,204

Canadian Energy Partnership for Environmental Research – 2011 Actual $83,996, 2012 Budget $56,000

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 10, page 6

Union is proposing to spend $.6 million in 2011, $3 million in 2012 and $5 million in 2013 on its Energy Technology and Innovation Canada program. Please provide a list of projects that have been pursued in 2011. Please provide a list of the projects planned for 2012 and the actual spending to date. For 2013 what projects are being considered?

Response:

In 2011 Union spent $111,850 on ETIC projects. Additionally, Union spent $473,100 on "ETIC like" projects that would have been coordinated through ETIC in 2011 but were not because the launch of ETIC was delayed until the Fall of 2011. Requested details of actual 2011 are shown below.

Column1	ETIC "like" Union Gas Projects(2011)	Total Cost	
1	ETIC - Annual Dues	$	69,650
2	ETIC- Gas Heat Pump Water Heater	$	19,500
3	ETIC - High Efficiency Water Heater study	$	22,700
5	Micro CHP Development	$	250,000
6	Efficiency Standards Development	$	45,000
7	Micro Cogen Market Assessment	$	11,200
8	Micro Cogen Residential Modelling	$	10,000
9	Thermal Storage Assessment	$	21,000
10	Plug and Play Thermal System Design	$	20,000
11	LEED Building Design Charrette	$	36,700
12	Recommissioning Assessment	$	45,500
13	Biogas Research	$	10,000
14	Micro CHP demo	$	23,700
	Total Actual Cost	$	584,950

In 2012, there are currently four approved ETIC projects with an estimated budget of $1.308 million. These projects have been identified below:

Column1	ETIC Approved Project	Total ETIC Cost
1	High Efficiency Water Heater Project	$ 1,100,000
2	Smart Energy International Collaboration - Commercial CHP Demo	$ 200,000
3	Thermal Metering Project	In Kind
4	CNGVA Transportation R&D Roadmap	$ 7,500

To date in 2012, Union has proposed 10 new projects to ETIC. These projects will result in an estimated Union expenditure of $1,161,000. A number of additional projects have been proposed by other ETIC members and all of these projects are currently going through the ETIC project selection process to confirm member interest and financial commitment to each project. Union's 10 proposed projects are specified below.

Column1	Proposed Union Gas Project (2012)	Total Est. Budget
1	Assessment of RNG Membrane cleanup technology	$ 50,000
2	Microbiological Activity Assessment	$ 100,000
3	SEN Canadian Inventory	$ 40,000
4	National SEN Vision	$ 75,000
5	Natural Gas implications of Net Zero Buildings	$ 30,000
6	Commercial Heat Pump Demonstration	$ 300,000
7	Opportunity assessment for NG fuel cells	$ 50,000
8	Competitive analysis of electric vs gas efficiency	$ 30,000
9	Hospital energy use benchmarking	$ 50,000
10	GHG emission tailpipe industrial pilot	$ 436,000
	Total Estimated Cost	$ 1,161,000

2013 projects being considered have not yet been specifically identified although some of the 2012 projects selected may also require funds to be committed for 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 10, page 1

In September 2010 the CGA Board of Directors approved the establishment of the energy technology innovation fund. Union is proposing to spend $5 million in 2013. What are the proposed spending levels for the other CGA members? If the investments are to help "Canada achieve a low carbon energy future and ensure the continued relevance of natural as a foundation fuel", why should Union's ratepayers alone, and not its shareholders, fund these projects? What is the annual level of spending currently undertaken by Spectra Energy regarding energy technology innovation?

Response:

Proposed spending levels for other CGA ETIC members are still being developed. Ratepayers have been requested to fund the ETIC program since they will be the primary beneficiary of technology innovation developed. For example, development of a higher efficiency end use appliance will reduce the gas use and energy bill for the end use ratepayer.

Union has also made a significant investment in the development of ETIC through its contribution to the establishment of this organization. Union participates in all subcommittees of the ETIC organization.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference**:** Exhibit D1, Tab 2, Page 6

Union indicates that its O&M budget for ETIC program will be $5.0 million and will be based on the 6 mainly natural gas utilities included in the 2011 EU scorecard.

a) Please identify the 6 EU utilities used in the scorecard.

b) Please provide Union's understanding of the level of approved funding provided by:

   i. Other Canadian gas utilities for the ETIC program in 2012 and 2013
   ii. US gas utilities for 2012 and 2013

c) Footnote 1, indicates that the ETIC budget was based on 0.29% of $1,830 million. Please explain the basis for using $1,830 million.

d) Please provide details on how the funds for 2011 were spent as well as the details for the proposed 2012 and 2013 spending.

e) Please indicate how much of these proposed funds for 2013 are allocated to Rate 20, Rate 25, Rate 100, and T1.

f) Please indicate specifically what benefits customers in Rate 20, Rate 25, Rate 100 and T1 will receive from the results of this program.

Response:

a) The 6 utilities used in the EU RD Scorecard are those listed in Table 1 at Exhibit D1, Tab 10, p.5.

b)
   i. Please see the response at Exhibit J.D-7-5-2.
   ii. Union understands that there are currently $27 million (US) in approved technology R&D funding across 25 states in the U.S. This funding is typically 2/3 operationally based and 1/3 end use efficiency based. On a per customer basis U.S utilities fund between $1 and $1.50 per customer per year.

(GTI testimony from Mr. Ron Edelstein, Director Regulatory and Government Relations testimony in Hearing # 10-11165).

c) The $1,830 million referenced equals Union's 2010 total operating revenue. This can be found at page 5 of the Union Gas Annual Report 2010 (found at Ex A3, Tab 2).

d) Please see the response at Exhibit J.D-7-5-1.

e) The costs associated with the ETIC program are allocated to rate classes in proportion to the average number of customers in each rate class. Almost all ETIC program costs are allocated to Union's four general service rate classes (Rates M1, M2, 01 and 10). Combined ETIC program costs allocated to Rate 20, Rate 25, Rate 100 and Rate T1 are less than $1000.

f) Benefits specific to Rate 20, Rate 25, Rate 100 and Rate T1 will depend on the specific projects included in the ETIC program.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit D1, Tab 10

Please provide details of Union's R&D expenditure in the 5-years prior to the 2007 Base Year and indicate whether any of that spending was included in its utility revenue requirement. If not, then please provide the rationale for that approach.

Response:

In the 5 years prior to the 2007 base year, Union's technology innovation spending did not exceed $0.250 million per year.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 10

Please provide the following information with respect to ETIC:

a) Most recent annual report or, if none available, financial statements;

b) The proposal to the CGA Board of Directors that they ultimately approved;

c) Current list of members, with their respective annual financial commitments;

d) Current list of investments, including in each case the name of the member sponsoring the investment, the investment to date, the total commitment for that particular investment, and for any investment that is more than $1 million, the proposal on which the investment was ultimately approved.

Response:

a) ETIC was established in late 2011 and financial statements are not yet available.

b) Please see Attachment 1 for a copy of the ETIC final approved Business Plan dated December 15, 2011. Appendix B to this plan has not been provided as it includes a list of historic member specific project investments which Union has not been authorized to provide.

c) Please see the response at Exhibit J.D-7-3-1.

d) Please see the response at Exhibit J.D-7-5-1.

Energy Technology & Innovation Canada

Business Plan

Final
December 15, 2011

Contents

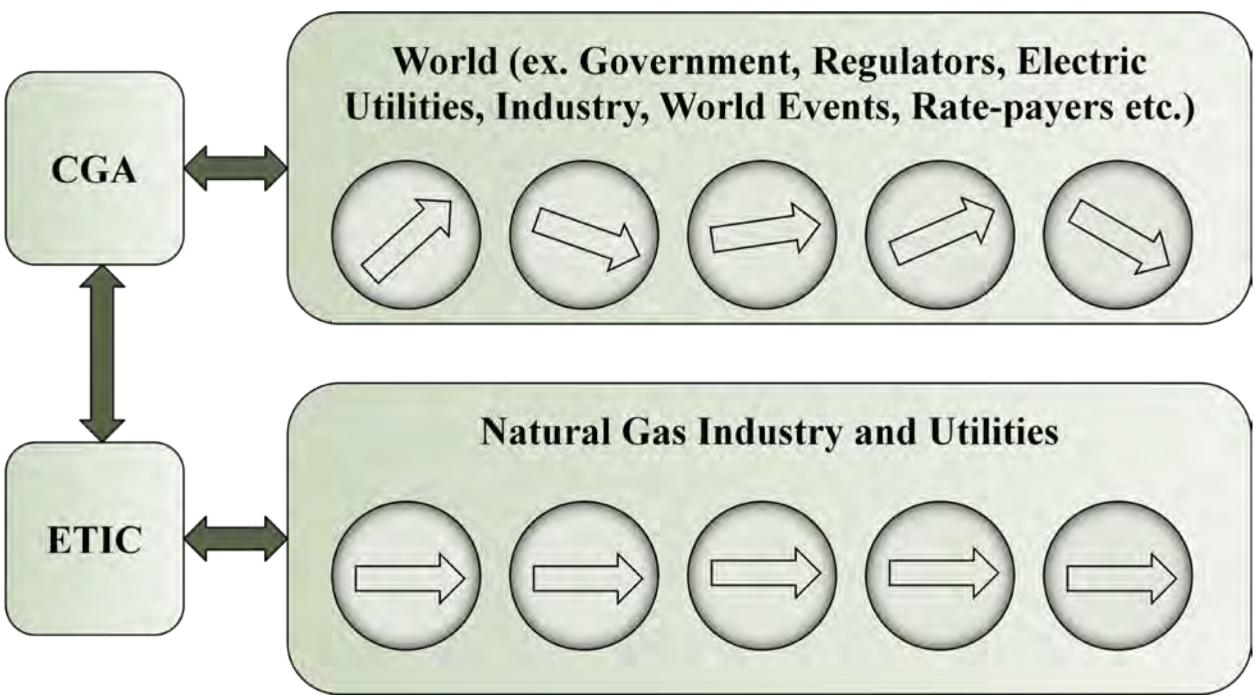
Figures

Tables

Introduction

Energy Technology and Innovation Canada (ETIC) is a major new initiative of the Canadian Gas Association (CGA) to mobilize investment in new end uses and greater efficiencies in existing uses of natural gas and gas-related technologies for Canadians. Natural gas is 30% of end use today. Abundant supply, robust infrastructure, decades of safe and reliable service, remarkably clean and efficient applications – all these attributes combine to prompt the question – "can natural gas do more still for Canada's energy needs of tomorrow?" The creation of ETIC represents the firm belief by Canada's natural gas delivery industry that natural gas is smart energy and a foundation for Canada's energy future. ETIC will build on the long history of support for efficient and innovative energy solutions by the natural gas delivery industry and help Canadian energy consumers lead a global trend towards smarter energy use.

Figure 1: ETIC Relationships & Purpose



ETIC will strive to have all NG industry and utilities in Canada aligned and working together in a fashion that allows for the greatest amount of progress for all in the area of Energy Technology and Innovation.

In the start up phase, ETIC will take direction from a CGA Committee with day to day direction provided by the CGA. The CGA will continue its work with domestic and global organizations such as large industry, government, regulators and academia.

ETIC will act as an information source and exchange, but it will also function as a proactive enabler and industry advocate focused on energy innovation and technology. The enabler role means ETIC will bring CGA member companies and other interested parties together to pursue common interests and goals. Through its membership structure ETIC has access to the CGA membership base – representing a wealth of know-how across the country – along with other industry, governments (municipal, provincial, federal and foreign), and academia. The advocate role builds on this – this is where ETIC makes the case for collective action on technology and innovation to leverage financial support from third parties in support of CGA members' core contributions.

ETIC will focus initially on four technology areas:

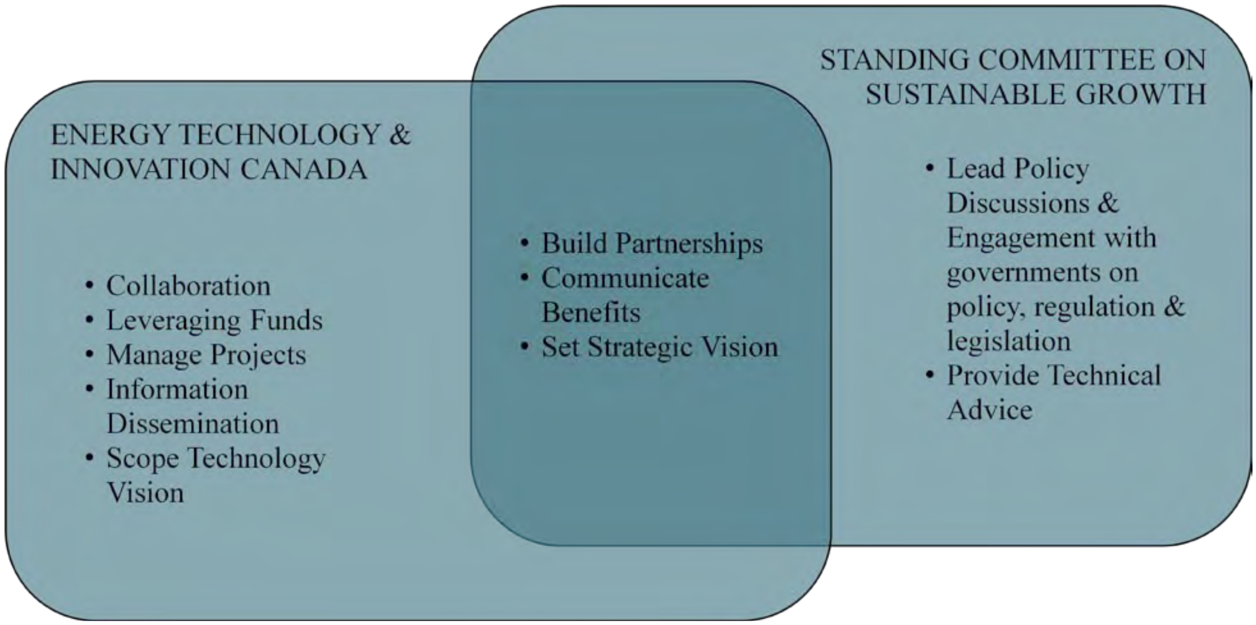
- Integrated Community Energy Systems (ICES),
- Renewable Natural Gas (RNG),
- Transportation and,
- Industrial Processes.

Initially ETIC will focus on deployment (or the removal of deployment barriers) and commercialization of technology in these four areas. Over time, its activities may also include technology transfer, applied research, product development, pilot and demonstration projects, technology road-mapping and market development.

Mandate:

- Be an enabler for investment in innovation in downstream end-use (new and/or improved) of gas and gas technologies.
- Support collaboration amongst CGA members and between them and third parties on such innovation.
- Leverage financial support and over time work to raise sustained funding.
- Work to remove barriers to deployment and commercialization of innovative technology.

Figure 2: Standing Committee on Sustainable Growth & ETIC: The Working Relationship



ETIC will take direction from the CGA and CGA Committees. Figure 2 outlines the discrete functions of ETIC and the key relevant CGA policy committee, the Standing Committee on Sustainable Growth (SCSG).

The ***Standing Committee on Sustainable Growth*** will continue to lead in encouraging or responding to federal government technology and innovation policy announcements, or regulatory and legislative action, which could affect natural gas end use and load. CGA and SCSG will also engage with government officials in respect to particular technical advice on technology matters, using ETIC as appropriate. In support of ETIC and its operations, SCSG and its members will continue to provide their technical and expert advice in areas of technology development and innovation.

Energy Technology & Innovation Canada will lead when a technology gap or opportunity has been identified, requiring deployment or commercialization activities, consultations, financial leveraging, etc. ETIC will also be a project manager for such efforts, looking to move them forward in the most effective way to the collective benefit of the funders involved. ETIC and SCSG will each work towards building partnerships and communicating to governments the benefits of investing in technology. Further, both parties will have a role in setting the strategic vision and priority areas for ETIC.

The formal launch of ETIC was be September 28, 2011. This Business Plan covers the period from the formal launch to the end of 2012 – an initial development period when ETIC launches a series of start-up projects aimed at building its reputation, testing its initial capacity to leverage support, and building a knowledge base on which to assess the move to a larger financial model. At the end of the second quarter of 2012, work will begin on a revised ETIC business plan that will present the next stages of ETICs development and growth.

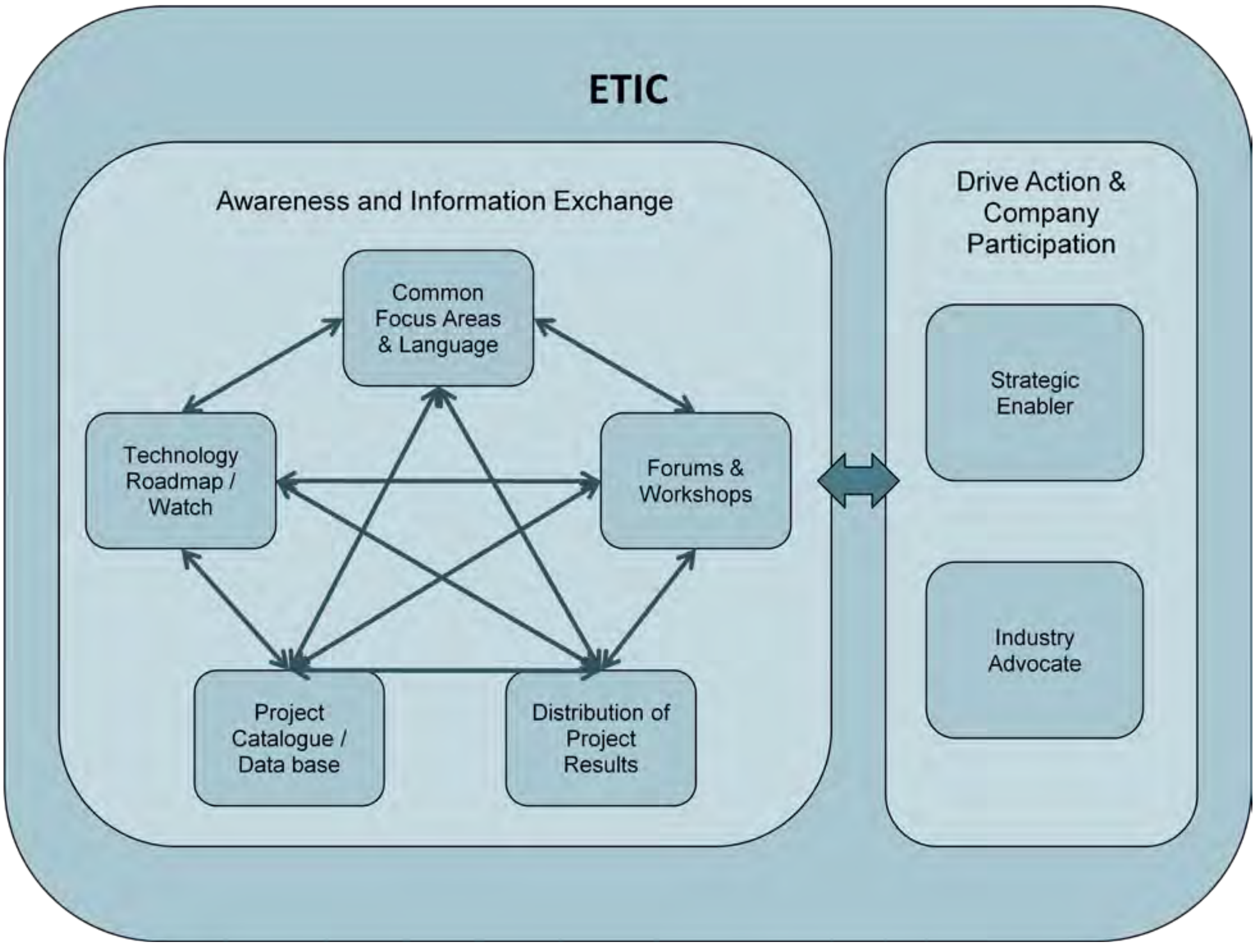
Timeline of Meetings

	Apr		May			Jun			Jul		Aug		Sep			Oct				Nov			Dec		
Operating Committee	3	24		8	22	12		26	10	24	14	28		11	25			9	23		13	27			19
Steering Committee			1										4							6					
CGA Board						12	13									2	3						4	5	
						AB										ON							call		

Products and Services

During the start-up phase, ETIC will develop and offer three kinds of services – information, enabling, and advocacy - that assist its members with technology and innovation opportunities. These services are intended to build some core competencies within ETIC that deliver value to members in and of themselves, but also help to build the capacity of the vehicle to more effectively assist with greater progress for all members in energy technology and innovation.

Figure 3: ETIC Services



I. Awareness and Information Exchange Activities

These include the following:

- Common Focus Areas – to ensure ongoing relevance to member interests
- “Technology Roadmap/Watch” - to monitor technology developments/discussions
- Project Catalogue – to document developments of note and maintain a collective memory
- Forums and Workshops – for networking and information exchange/education
- Distribution of Project Results – to ensure all can derive benefits

(i) Common Focus Areas

ETIC has identified an initial focus on four technology areas:

- Integrated Community Energy Systems (ICES),
- Renewable Natural Gas (RNG),
- Transportation and,
- Industrial Processes.

A description of each technology area is presented in Appendix A. Over time this list may be amended, depending on member interests. The assessment of the relevance of these four areas will be ongoing.

(ii) Technology Roadmap/Watch

A quarterly electronic report to be issued to the members on new developments in technology related to renewable natural gas, integrated community energy systems, transportation and industrial applications. This will also include emerging trends, evolving technologies of interest and developments in other technology areas that can impact LDCs. Company staff in member companies who track or come across relevant information will be called on to provide raw content which will be then shared with all ETIC members and select partners.

(iii) Project Catalogue

ETIC, through ongoing activities such as annual surveys of its members, will determine:

- Company investment on technology, broken down by type (capital, O&M) and per technology area
- Projected technology investment budget for the upcoming year, and unallocated funds or funds that can be redirected to collaborative initiatives in the upcoming year

The results will be shared with ETIC members and select partners.

(iv) Forums and Workshops

Fall Technology Planning Meeting

Every fall, ETIC will host a forum for members to:

- Discuss the technology trends identified by the technology watch,
- Validate or shift the technology focus of ETIC
- Receive an update on progress of ongoing projects
- Identify potential new project concepts and available funding and
- Set project leads and the deadline for proposals (project leads may be members, ETIC, or external stakeholders)
- Confirm/modify planned activities for the balance of the year
- Review unsolicited proposals or project proposals from international partners

ETIC will develop a portfolio of project proposals and send these to members and potential funding partners by the end of Q2, for discussion and decision at the fall workshop.

Annual Technology Workshop(s)

ETIC will hold a workshop every spring, dedicated to one of the four technology focus areas. Participation will be by invitation and open to non-member stake-holders, e.g. technology suppliers, value-chain partners, topic experts, researchers, international stakeholders, government representatives, etc. Suppliers will be invited to showcase their technologies and services. Experts from outside the industry will be invited to present their work and potential project ideas. Members will present the key findings of the projects each has completed in the last year.

2011 – The strategic retreat is the 2011 substitute for the first Fall Technology Planning Meeting.

2012 - the first Spring Technology Workshop will occur early in 2012 and will focus on RNG. Activities around policy issues on RNG are already part of the SCSG agenda for early 2012.

The technology workshops will build momentum around the LDC technology focus areas, and establish ETIC as the focal point of collaborative action in the given technology focus area. It will also serve as a forum to shape and disseminate a technology road map for each of the four focus areas: RNG, ICES, transportation and industrial.

(v) Distribution of Project Results

ETIC will develop a repository of project files and project results. Results such as data and final reports will be made available to all ETIC members and select partners.

II. Strategic Enabling Services

Annual Project Selection Process

A members-only session will be held in conjunction with the fall workshop where ETIC members review the proposals, select the projects for collaborative action for the next year and allocate funding. The contribution of each company may vary from project to project depending on the interest of the companies. Collaborative projects may include members contributing to ongoing projects in each company as well as collaborating on new projects.

ETIC will develop the rules for accessing outside projects such as those of the European Gas Research Group (GERG) and Gas Technology Institute / Utilization Technology Development (GTI/UTD). It may be possible to integrate these with the annual fall workshop by inviting GERG and GTI to the fall workshop. Alternatively, ETIC may need to participate in their respective processes.

Catalyst for Partnership Formations

ETIC will continuously and consistently seek out and facilitate the formation of partnerships that will allow NG utilities in Canada to work together and in an aligned fashion that allows for the greatest amount of progress for all in the area of Energy Technology and Innovation. ETIC will seek to serve as the catalyst that leads to partnerships being formed, formalized and exercised. It will also act as an intermediary between parties in negotiating agreements and facilitate the management and completion of multi-partner projects and initiatives.

III. Industry Advocate Services

Demonstrate the Value of Collaboration

ETIC will report on the benefits of each project, and the value of collaboration. ETIC will also track and report on the leverage on investment for members. In the start-up phase leverage will primarily come from collaboration among the companies. ETIC will evaluate the potential and pursue co-funding from government or other partners on a project-by-project bases. Additional leverage may also come from international partnerships with organizations such as GDF Suez, Advanced Energy Research & Technology Center (AERTC), GERG and GTI/UTD.

Showcase Industry Investment

An annual publication will showcase an inventory of current industry investment, projects and key findings, demonstrate the benefits, present the leverage on every dollar invested per company or by industry. Over time, this can evolve to serve as a quantitative basis for approaching government and regulators for increased investment in a collaborative effort.

Raise the ETIC and Industry Profile

ETIC will seek to raise its profile through activities that may include:

- Establishing an honorary advisory board composed of high profile individuals with an interest in/connection to technology and innovation (including a high profile honorary chair).
- Publicizing new technology developments, projects, and partnerships
- Looking for opportunities to showcase the industry technology activities in conferences, workshops, etc.
- Encouraging academic research to focus on areas of interest (e.g. a “Chair of RNG Studies” at a Canadian University, a network of centers of excellence for ICES, etc)
- Working & Networking Relationships with Other Institutions such as GTI/UTD, NRCAN, Utilities, Municipalities, technology providers etc.
- Hosting events

Marketing Plan

ETIC will provide a focused effort that serves the strategic innovation and development needs of the gas industry in Canada. This has been lacking for a long time. The unbundling and de-regulation of the industry in the 90s resulted in a sharp decline in collaborative technology development among distribution utilities. The result has been particularly noticeable on natural gas utilization. It was assumed the market would continue to innovate and develop new NG technologies. Unfortunately, this did not happen and gas markets suffered. A large void in the commercialization process of new innovative NG technologies exists. At the same time, the level of investment has increased in the areas of smart electric grids and renewable energy – usually funded by state initiatives – fed in no small part by perceptions about electricity being cleaner or more efficient. The major advances in controls, communications and materials that resulted did not find their way into gas appliances and equipment.

In light of the above, the energy discourse has become more and more about electricity, risking serious marginalization for NG. A few more recent events have produced a silver lining however.

Globally, the role of NG in providing energy is set to increase thanks primarily to new unconventional sources including “shale gas”, “tight gas” and possibly “hydrates” moving forward. New supply has made the prospect of longer term price stability for natural gas a real one, opening the door to a reassessment of the role of gas vis-à-vis increasingly costly energy alternatives like renewable. In addition, a general fatigue with some environmental advocacy has prompted a reconsideration of the potential value of NG as the clean hydrocarbon.

The recent developments present an opportunity to be seized: it is possible for Canada to build on our existing natural gas and gas-enabled technology expertise and ETIC offers a vehicle through which to do that. The possibility of NG use in new applications or the expansion of existing ones, is a real one, with benefits for the whole natural gas value chain, and the national economy as a whole.

Initially the overall focus of ETIC will be to facilitate and drive natural gas technology innovation that ensures the natural gas remains the smart energy foundation to Canada’s energy system.
This will be achieved through identifying technology gaps of interest, accessing and sharing information among the member companies and with others, strategic investment in technology commercialization and innovation, showcasing of innovative gas and gas-enabled solutions, partnering with technology suppliers, and influencing the research and development community.

Pre-Launch (September 2010 – September 2011)

This phase was focused on starting the organization and preparing for the formal launch that occurred on September 28, 2011. The key deliverables for this phase have been:

- Securing early wins: inventory of activity, information exchange among members, 1-2 new projects & partnerships

- Creating an identity: logo, website

- Hosting a steering committee retreat to assess progress, approve a plan for the period through to the end of 2012, and approve a governance model

- Arranging for the official launch coordinated with CGA

Virtual Organization (September 2011 – December 2012)

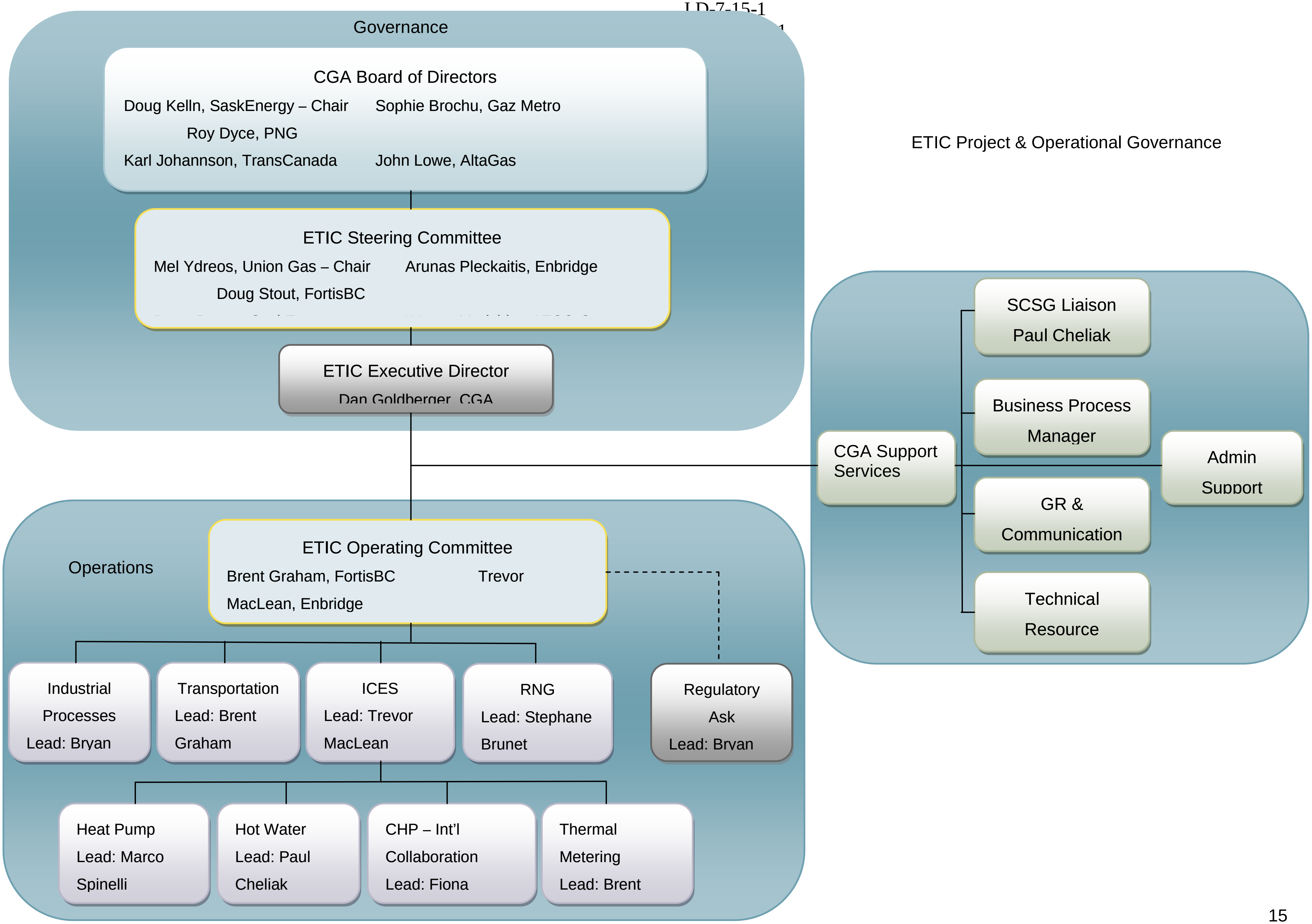
This phase covers the period from the formal launch to the creation of a separate (but still CGA-run) legal entity. The key deliverables for this phase are as follows:

- Formalization of governance, membership and financing structure.
- Establishment of organization and management structure linked in to CGA.
- Membership engagement structure (project selection, funding, dissemination of findings).
- Definition of rules around free ridership, participation and rights.
- 1st cycle of delivering all services and products identified in the products and services section of this report.
- Business development to lay the ground work for attracting long-term funding partners.
- Formalized relationship with program managers and technology performers.
- Securing of LDC approval for new projects for 2012.
- Focused engagement of NRCan and select stakeholders (especially NG producers) for co-funding
- Launching of first round of projects.

Management and Organization Functions

Organization Structure

In the 1st Phase of ETIC (i.e. launch to end of 2012), all resources and functions will be provided by the CGA and ETIC member companies. The overall organization structure of ETIC is represented in the figure below. A description of each function is described in the sections that follow.


ETIC Project & Operational Governance
Governance
CGA Board of Directors
Doug Kelln, SaskEnergy – Chair
Sophie Brochu, Gaz Metro
Roy Dyce, PNG
Karl Johannson, TransCanada
John Lowe, AltaGas
ETIC Steering Committee
Mel Ydreos, Union Gas – Chair
Arunas Pleckaitis, Enbridge
Doug Stout, FortisBC
ETIC Executive Director
Dan Goldberger, CGA
CGA Support Services
SCSG Liaison
Paul Cheliak
Business Process Manager
GR & Communication
Technical Resource
Admin Support
Operations
ETIC Operating Committee
Brent Graham, FortisBC
Trevor MacLean, Enbridge
Industrial Processes
Lead: Bryan
Transportation
Lead: Brent Graham
ICES
Lead: Trevor MacLean
RNG
Lead: Stephane Brunet
Regulatory Ask
Lead: Bryan
Heat Pump
Lead: Marco Spinelli
Hot Water
Lead: Paul Cheliak
CHP – Int'l Collaboration
Lead: Fiona
Thermal Metering
Lead: Brent

Steering Committee

- Mel Ydreos, Union Gas - Chair
- Arunas Pleckaitis, Enbridge
- Doug Stout, FortisBC
- Dean Reeve, SaskEnergy
- Wayne Morishita, ATCO Gas
- Lloyd Kuczek, Manitoba Hydro
- J.B. Allard, Gaz Métro
- Greg Johnston, AltaGas Utilities
- Sam Bernstein*, STAR Energy Capital
- Tim Egan, Canadian Gas Association

Executive Director

- Dan Goldberger, CGA

Operating Committee

- Trevor MacLean, Enbridge
- Brent Graham, FortisBC
- Bryan Goulden, Union Gas
- Stephane Brunet, NGTC
- Walter Dunnewold, ATCO Gas
- James Gates, SaskEnergy

ETIC Staff

- Marco Spinelli, Enbridge - Business Process Manager
- Brendan Hawley, Contractor to CGA - Government Relations
- Paula Dunlop, CGA - Analysis & Communication
- Paul Cheliak, CGA –
- Utilities, as required – Technical Resource

- Deborah Pfeil, CGA - Administrative Support

Other Members of Operations

- Fiona Oliver-Glasford, Union Gas
- Sam Bernstein*, STAR Energy Capital

Renewable Natural Gas

- Paul Cheliak, CGA
- Stephane Brunet, NGTC
- Owen Schneider, EGD
- Ed Seaward, Union

Integrated Community Energy Systems

- James Gates, SaskEnergy - Micro Combined Heat & Power
- Fiona Oliver-Glasford, Union Gas - International Collaboration
- Paul Cheliak, CGA - Remote Communities
- Paul Cheliak, CGA - HE Water Heater Project
- Thermal Metering
    - Brent Graham, FortisBC
    - Stephane Brunet, NGTC
    - Trevor MacLean, Enbridge
    - John Overall, Union Gas
    - Darren McIlwraith, Enbridge

Industrial Processes

- Bryan Goulden

Transportation

- Brent Graham

Steering Committee

The role of the Steering Committee is to provide governance, resources the operating budget, and long-term direction. Each member company of ETIC will have one seat on the Steering Committee. Each member is expected to have an executive level position in their own organizations. Each member of the Steering Committee has one vote. All member companies will have access to all program and project results and reports.

Operating Committee

The operating committee is responsible for setting research priorities, allocating project budget monies and providing technical direction for the projects and operation of ETIC. The original start-up group has transformed into the operating committee. Each seat on this committee will have one vote.

Program Technical Steering Group

One Program Technical Steering Group has been developed for each of the 4 program areas (i.e. Integrated Community Energy Systems, Renewable Natural Gas, Transportation and Industrial Processes). Each program will have a steering group chair, selected from the members of the Operating Committee. This will ensure that steering groups are aligned with the direction and goals of the Operating Committee.

Working with the Executive Director and Operating Committee, each steering group will be responsible for providing technical direction, scope generation, performer selection, work plan development and approval, progress reviews & review, approve and disseminate findings. Membership may be open to non-members of ETIC and will be selected from industry experts nominated by the operating committee. Non-members of ETIC will have an advisory role and no-voting power.

Executive Director

The Executive Director of ETIC will provide high level direction and day to day management of the ETIC operation. The key functions of the Executive Director are Business Development, growth and development of ETIC, management of all stakeholder expectations.

Government Relations (GR) & Communications

Support that will be provided by or through the CGA will be tasked with linking the needs of government offices with ETIC offerings. The GR will explore opportunities for government support of the ETIC agenda, and make key connections between ETIC and outside parties such as elected representatives and government offices.

The Communications function will coordinate the development and distribution of publicity material, ETIC web site, presentations etc. The intent is to develop one look and style to which all ETIC communication material will follow. This function will also coordinate publicity events such as the ETIC launch. This will be a shared resource with the CGA.

Business Process Management

The Business Process Management Function will be accountable for all money budgeted & spent and all contracts being developed negotiated and signed by ETIC. This management function will be provided by the CGA.

Technical Resource

The Technical Resource will be filled by experts on an as needed basis. This group of resources may expand and contract in size depending on the size, activity and complexity of the ETIC program portfolio.

Legal

Outside legal support will be provided by the CGA.

Information Technology

Outside Information Technology support will provided through the CGA.

Miscellaneous Resources

Miscellaneous resources such as facilitators and web page designers will be outsourced.

Functional Support Acquisition Timeline

Below is a functional support acquisition timeline. In the 1st 2 phases of ETIC (i.e. Start-Up and ETIC Operational) the functional support noted below will be required. In these phases, as many resources as possible will be secured from member companies in the form of secondment or simply though giving member company resources assignments specific to ETIC activities. These assignments will be managed and facilitated by the Operating Committee. The functional support required by ETIC will be a function of ETIC activity levels and will grow in line with ETIC demands.

Table 1: Functional Support Acquisition Schedule

		3Q11	4Q11	1Q12	2Q12
ETIC Staff	Executive Director & Business Development	*			
	Government Relations		*		
	Analysis / Communications		*		
	Business Process Manager		*		
	Technical Resource	*			
	Administrative Assistant	*			
Governance	Board of Directors		*		
	Operating Committee	*			
	Program Advisory Group 1: RNG		*		
	Program Advisory Group 2: Int. Comm. Energy Systems		*		
	Program Advisory Group 3: Transport		*		
	Program Advisory Group 4: Industrial				*
Services	Facilitator	*			
	Communications	*			
	Legal		*		
	Information Technology	*			

Operational Plan

Product and Service Creation

At the start up ETIC will monitor a few select projects and share the results and benefits of these projects with all ETIC members. The ETIC start-up group has selected 4 key program areas and projects within these program areas will form the initial portfolio of projects brokered by ETIC.

Products and Services as described in this business plan will have their 1^{st} offing as follows:

- Quarterly Technology Watch & Technology Roadmap – Date TBD
- Publication of Summary of Technology Investment and Catalogue of Projects – Date TBD
- Spring Technology Planning Meeting – Date TBD
- Annual Technology Workshop – Date TBD
- Annual Project Selection Process Completed – Date TBD
- ETIC Annual Report – Date TBD

Strategic Partnerships

ETIC will pursue relationships with third parties who are involved on the ground in technology research, development, deployment and commercialization. These may take the form of contracts, MOU's or other written agreements. In each case the idea is to leverage off of existing work being done to maximize opportunities.

Management of ETIC Funding

A yearly membership fee will be charged to all ETIC members to cover overhead and miscellaneous expenses such as member meetings, legal, IT and office space. A notional overhead & miscellaneous budget of $350,000 for 2012 (identical to the 2011 allocation) is proposed. This budget will be allocated amongst member companies in accord with the allocation formula for their contributions to CGA. Specific technology funding will remain with the member companies. Each company that joins ETIC will have one seat on the Steering Committee.

Intellectual Property

IP will be formally owned by ETIC or as indicated in performance contracts between ETIC and all partners/stakeholders. All ETIC members will be given unlimited and unconditional use of any IP generated for their own personal use. Organizations outside of ETIC members must ask ETIC for permission to use IP.

Major Milestones

- High Efficiency Hot Water Heater Project - Underway
- Draft Business Plan to Retreat attendees - September 13 2011
- ETIC Board Retreat – September 15 2011
- Draft of Regulatory Ask paper to operating committee – September 26 2011
- Formal Launch – September 28 2011
- Thermal Metering Government Relations Strategy Finalized – end of calendar 2011
- CGA/NGTC Discussion for RNG Opportunities & Area of Interest –end of calendar 2011
- Quarterly Technology Watch & Technology Roadmap – First quarter 2012
- Publication of Summary of Technology Investment and Catalogue of Projects – evergreen
- Spring Technology Workshop 2012 - Focus: RNG – 2012 Date TBF
- Fall Technology Planning Meeting – September 4 2012 - TBC
- Annual Project Selection Process Completed – Date TBD
- ETIC Annual Report – Date TBD
- Updated ETIC Business Plan for 2013 and beyond – Q2-Q3 2012

Structure and Financial Plan

Legal Form of ETIC

ETIC will remain as an initiative of the CGA. It is expected that beyond 2012, ETIC may be incorporated as a not for profit corporation with one member, the CGA.

Appendix A: Technology Areas of Interest

a) Integrated Community Energy Systems

b) Renewable Natural Gas

c) Transportation

d) Industrial Processes

Introduction:

An integrated community energy system is an integrated approach to supplying a local community with its energy requirements from multiple energy sources that may include a variety of supply options including renewable energy and high-efficiency co-generation energy sources. The approach can be seen as a further development of the distributed generation concept. Such systems are based on a combination of district heating, district cooling, plus 'electricity generation islands' that are interlinked via a private wire electricity system. The surplus from one generating island can be used to make up the deficit at another.

Objective

The objective is to ensure that as integrated community energy systems are developed in Canada, natural gas will continue to be a foundation fuel, not a transitional fuel, in these energy systems.

Industry Need

Industry requires a reliable and cost competitive delivery of energy, whether from conventional pipes and wires services or district energy. The providers of these services will need to be reputable and responsive to the ever increasing expectations from customers.

As the world continues to face increasing challenges from the effects of climate change, the unique abilities of district energy to deliver energy efficiently and with enormous flexibility is expected to become a key demand from end-users.

Scope

ETIC projects that would fall into this category would involve the following technologies:

- Smart Energy Grid
- Thermal Metering
- Combined Heat & Power (CHP)
- Micro Combined Heat & Power (mCHP)
- Thermal Storage
- Hybrid Gas/Renewable Technologies
- Water Heating Technologies

Business Value

As natural gas continues to attract attention in global and local efforts to reduce GHG emissions, natural gas utilities will continue to find their core market (i.e. space & water heating) share eroded away to other sources of energy that are seen as more environmentally friendly.

Improvements to NG equipment efficiency, changes to the building codes and consumer attitudes towards energy savings have all lead to a decline in average per capita consumption of natural gas. This trend has been visible over the last 10 years and is expected to continue.

Natural Gas Utilities must decide how to continue to operate in this changing environment. One option is to transform from a distributor of natural gas to a distributor of energy. District energy and integrated community energy systems will provide a market to expand into. NG utilities are well equipped to offer the service of distributing natural gas, and by extension, hot water, steam and/or cold water in an efficient and cost competitive way. Furthermore, utilities are regulated. Customers who purchase energy from a regulated utility can be assured that the rates they are charged for the energy they consume has been intensely scrutinized and approved by a regulatory body that has their best interests in mind.

In summary, the development of integrated community energy systems provides a market into which NG utilities can grow and expand their service offerings. In turn this will allow NG utilities to transform themselves from distributors of NG to distributors of energy and secure their future growth and sustainability.

Ontario is on target to shut down the last 2 remaining coal fired electricity generation plants by the end of 2014. Once these plants have been shut down, attention will turn to natural gas and transportation as the greatest source of green house gas emissions in Ontario. While comparably aggressive strategies do not exist in other provinces, the overall trend is towards the elimination of coal. In that scenario, natural gas could become the new target. Part of a strategy to avoid that outcome is to produce, distribute and consume renewable natural gas – a widely available resource that can help counter common criticism of use of conventional gas supply.

In the effort to reduce emissions that come from the consumption of natural gas, the following options are available:

- Replace or upgrade existing equipment that consumes natural gas with higher efficiency equipment.
- Improve building envelops. This includes improving the building envelops of all buildings, of all ages.
- Change consumer behavior.
- 'Green' the natural gas supply through the injection of renewable natural gas.

Efforts have been under way with the first three options for some time. Work on the use of RNG is more recent and may offer significant economic opportunity.

Several industry interests can be advanced through a program to promote RNG use:

- RNG offers value as a significant Canadian supply option for the long term.
- It is a supply option which offers a better emissions profile than conventional gas consumption.
- It is a supply option that over time may mitigate against price volatility in the market
- It is being used elsewhere and Canada can benefit from that experience.
- Present proven technology from abroad in anaerobic digestion (AD) and landfill (LF) gas management can be tested and adapted to Canadian conditions through an ETIC RNG program.
- The long term development of gasification is required to bring down the cost of RNG and an ETIC program could help assess possibilities.
- An RNG strategy helps improve the positioning of natural gas as a smart environmental performer in the energy marketplace.

Transportation

The following was taken from the executive summary of the recently published report, *<u>'Natural Gas Use in the Canadian Transportation Sector, Deployment Roadmap'</u>,* prepared by the Natural Gas Use in Transportation Roundtable (December 2010).

> "Canada's transportation sector is characterized by high energy use and significant greenhouse gas (GHG) emissions. In 2007, transportation accounted for 29 percent of secondary energy use, making it Canada's second-largest sector in terms of energy consumption.[1] Unlike most other sectors of the Canadian economy though, transportation relies on a single energy source (crude oil-based fuels) to meet the vast majority of its energy needs. Energy demand for transportation is increasing, and vehicle energy use is projected to increase by 31 percent between 2004 and 2020.[2] GHG emissions from transportation sources are also rising. More than one-third of the increase in Canada's GHG emissions between 1990 and 2008 was attributable to transportation sources.[3] To address the transportation sector's increasing energy demand and GHG emissions, a comprehensive strategy is needed to improve vehicle efficiency, increase the use of lower-carbon fuels, and enhance system efficiencies. The increased use of natural gas in the transportation sector is one component of the overall solution.
>
> Canada's natural gas supplies have grown substantially in recent years due to the advent of new drilling technology. Canada's transportation sector could benefit from expanding the use of lower-emission technologies and fuels such as natural gas. For medium-and heavy-duty vehicles that operate in return-to base and corridor fleets, natural gas offers some important potential benefits, such as the ability to:
>
> - Diversify energy use in the transportation sector and meet increasing energy demand;
> - Reduce carbon emissions from the transportation sector;
> - Introduce into a new market a cost-effective fuel that has historically traded at a discount to crude oil-based fuels on an energy equivalent basis; and
> - Provide an alternative compliance option as carbon-related regulations enter the transportation sector. "

Despite the benefits of NG vehicles, the adoption of such vehicles in Canada has been very limited. ETIC could focus on the proliferation of NG technology in the transportation industry addressing barriers such as:

- Operating risks associated with costs and technology performance
- High upfront vehicle costs.
- Lack of widespread infrastructure
- Non-economic barriers such as scarce recent public experience with NG vehicles, insufficient information about current technology and a lack of comfort with NH vehicles.

Industrial Processes

TBD

Objective

Industry Need

Scope

Stakeholder Relationships

Business Value

Appendix B: Summary, Annual Survey of Technology Investment

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.1

Union provided the updates of the assumptions used to calculate Union's defined benefit pension and post-retirement benefits costs forecast for 2012 and 2013. Union stated that the assumptions are finalized at the 2011 year end.

a) Please provide the actuarial report to support these assumptions and confirm that the actuarial report is reviewed by Union's external auditor.

b) If the actuarial report is not available,
  - please provide the date when it will be available and filed with the Board;
  - please provide the most recent actuarial report available and confirm that the report is reviewed by Union's external auditor.

Response:

a) and b) Attachment 1 is a redacted version of the actuarial report prepared by Towers Watson. This report provides financial information for Employee Future Benefit Programs for Westcoast Energy. The actuarial assumptions and accounting detail specific to companies other than Union Gas have been redacted.

The actuarial report which details the actuarial assumptions in Appendix A is attached. Union's external auditors were provided with a copy of the actuarial report and confirm that the assumptions that they have deemed necessary to issue an audit opinion on have been audited. Union's external auditors receive a signed confirmation from Towers Watson which confirms they understand they are relying on their work. In addition, the external auditors confirm that the preparers of the actuarial report are in good standing with the Canadian Institute of Actuaries.

SPECTRA ENERGY TRANSMISSION

Financial Information for Employee Future Benefit Programs

as at December 31, 2011

in Accordance with ASC 715

January 2012

TOWERS WATSON

Table of Contents

Introduction

This report has been prepared for Spectra Energy Transmission (the "Company"), as requested by the Company, and presents financial information with respect to the employee future benefits provided to Canadian employees for both US and Canadian reporting, in accordance with Section 715 of the Financial Accounting Standards Board's Accountings Standards Codification ("ASC 715").

The Company prepares financial information in accordance with ASC 715 for both US and Canadian reporting purposes. The actuarial methods and assumptions, the membership data and the asset valuation methods are identical under US and Canadian reporting. Accordingly, the projected benefit obligations, current service costs and value of assets are also identical under US and Canadian reporting. However, differences in the past recognition of unamortized amounts result in different unamortized amounts, amortizations and net benefit costs under US and Canadian reporting. Further details on the development of the unamortized amounts is provided in the Accounting Policies section of this report.

Towers Watson Canada Inc. ("Towers Watson") is aware that the information contained in this report will be used, in accordance with the CIA/CICA Joint Policy Statement, to support the audit of the Company's financial statements by Deloitte & Touche LLP for the fiscal year ended December 31, 2011. This report has been prepared in accordance with the CIA/CICA Joint Policy Statement.

The principal purposes of the report are:

- to present information on the net benefit cost for 2011 in accordance with ASC 715; and
- to present information required for the 2011 year-end disclosure in accordance with ASC 715.

We are not aware of events that occurred during 2011 that would give rise to either a settlement or a curtailment.

[redacted]

The remainder of this report provides details with respect to the covered benefits, membership data, plan assets, plan provisions, accounting policies, actuarial methods and assumptions and required information under ASC 715.

The information contained in this report was prepared for Spectra Energy Transmission, for its internal use, in the disclosure of the net benefit cost and related disclosure items for future benefit costs and obligations in Spectra Energy Transmission's financial statements in connection with Towers Watson's actuarial valuation of employee future benefit programs for accounting purposes. This report is not intended nor necessarily suitable for other purposes. Further distribution of all or part of this report to other parties or other use of this report is expressly prohibited without Towers Watson's prior written consent.

Covered Benefits

To our knowledge, this report provides information on all post-employment benefits provided by the Company to its Canadian employees that are material to the Company's financial statements.

Registered Pension Plans

Our calculations include the following registered pension plans:

- Pension Choices Plan for Employees of Westcoast Energy Inc. and Affiliated Companies (the "Pension Choices Plan");
- Westcoast Energy Inc. Employees' Retirement Plan (the "Westcoast Plan");
- Union Gas Management and Supervisory Pension Plan (the "M&S Plan");
- Union Gas Bargaining Unit Pension Plan (the "Bargaining Unit Plan");
- Union Gas Pension Plan for Salaried Employees Formerly Employed by Centra Gas Inc. (the "Centra Salaried Plan");
- Union Gas Pension Plan – Group One (the "Group One Plan"); and
- Union Gas Pension Plan – Group Three (the "Group Three Plan").

The Pension Choices Plan includes a defined contribution provision ("DC Core") and defined benefit ancillary accounts ("DB Ancillary Accounts"). This report does not include any assets or obligations in respect of DC Core or the DB Ancillary Accounts.

The most recent actuarial valuation funding reports for the registered pension plans, as filed with applicable regulatory authorities, and the next required actuarial valuation funding reports are as follows:

	Most recent valuation	*Next required valuation*
Pension Choices Plan	January 1, 2011	January 1, 2014
Westcoast Plan	[redacted]	[redacted]
M&S Plan	January 1, 2011	January 1, 2014
Bargaining Unit Plan	January 1, 2011	January 1, 2012
Centra Salaried Plan	January 1, 2011	January 1, 2012
Group One Plan	January 1, 2011	January 1, 2012
Group Three Plan	January 1, 2011	January 1, 2012

Supplemental Pension Arrangements

There are three types of supplemental pension arrangements:

- Individual Severance and Retirement Compensation Agreements for senior executives (the "SRCAs");
- Supplemental Executive Retirement Plan covering other executives (the "Executive Arrangements"); and
- A general hold harmless arrangement for all employees that provides pension benefits which are in excess of the Income Tax Act maximum pension limit (the "SEMPL Benefits").

Our calculations include all obligations associated with these three arrangements.

Post-Retirement Benefits Other Than Pensions

The Company provides certain post-retirement benefits other than pensions. Benefits include extended health care benefits, dental care, group life insurance, payment of provincial health care premiums and a health care spending account. Our calculations include provision for all of these post-retirement benefits other than pensions.

Value of Assets

The fair value of assets is equal to the market value of assets as at December 31, 2011, based on the fund statements provided by CIBC Mellon, and adjusted as follows:

- All assets related to the DC Core component of the Pension Choices Plan have been excluded.
- All assets related to DB Ancillary Accounts under the Pension Choices Plan have been excluded.

The market related value of assets has been determined as the three year average of the fair values of assets. The ratio that the average of adjusted unit values bears to the actual unit value is first determined as the ratio of i) to ii), where:

i) Equals the average of the unit value under the Master Trust at the valuation date and the two previous adjusted unit values. The adjusted unit values are equal to the unit values at the two preceding anniversaries increased each year with an assumed investment return equal to the average yield on 3-month Canada Treasury Bills during the year plus 2.5%.

ii) Equals the unit value under the Master Trust at the valuation date.

The market related value of assets is calculated as the fair value of assets multiplied by the above ratio.

As at December 31, 2010, the market related value of assets was equal to 90.8% of the fair value of assets.

As at December 31, 2011, the market related value of assets was equal to 99.3% of the fair value of assets.

Towers Watson does not take responsibility for the information provided by CIBC Mellon.

Plan Provisions

Our calculations are based on the provisions of each plan as at December 31, 2011 and take into account all known substantive commitments made by the Company with respect to the covered benefits.

[redacted]

There were no other changes to the plan provisions between December 31, 2010 and December 31, 2011 that have a material effect on the financial position of the plans.

Summaries of the plan provisions for the covered benefits may be found in Appendix D.

Accounting Policies

The Company has adopted the following accounting policies, in accordance with the requirements of ASC 715:

For the purposes of US reporting:

- For the purposes of US reporting, upon Duke Energy Corporation's acquisition of Westcoast, effective March 14, 2002, the net funded status of all covered benefits were immediately recognized on the balance sheet as accrued benefit assets (liabilities);
- increases in prior service costs are amortized over the Expected Average Remaining Service Life ("EARSL") of employees who are active as of the date such costs are first recognized;
- the net actuarial gains or losses, including the effect of assumption changes, that exceeds 10% of the greater of the projected benefit obligation and the market related value of plan assets as of the beginning of the period (the "10% corridor"), are amortized over the EARSL of employees who are active as of the date such amounts are recognized;
- prior to January 1, 2007, a measurement date of September 30 was used and effective January 1, 2007, a measurement date of December 31 is used; and
- the market related value of assets (based on the average of the market value as at the valuation date and the adjusted market values projected from the two previous anniversaries) is used to determine the expected return on plan assets and the amount of amortization of the net actuarial gains or losses.

For the purposes of Canadian reporting:

- Increases in prior service costs are amortized over the Expected Average Remaining Service Life ("EARSL") of employees who are active as of the date such costs are first recognized;
- the net actuarial gains or losses, including the effect of assumption changes, that exceeds 10% of the greater of the projected benefit obligation and the market related value of plan assets as of the beginning of the period (the "10% corridor"), are amortized over the EARSL of employees who are active as of the date such amounts are recognized;
- prior to January 1, 2007, a measurement date of September 30 was used and effective January 1, 2007, a measurement date of December 31 is used; and
- the market related value of assets (based on the average of the market value as at the valuation date and the adjusted market values projected from the two previous anniversaries) is used to determine the expected return on plan assets and the amount of amortization of the net actuarial gains or losses.

Actuarial Basis

The actuarial cost method used is the projected benefit method prorated on services, also known as the projected unit credit (with linear proration on service) actuarial cost method.

Registered Pension Plans and Supplemental Pension Arrangements

Prospective benefits were calculated for each active and disabled member according to the actuarial assumptions shown in Appendix A. The projected benefit obligation for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits earned in respect of credited service prior to the valuation date.

The projected benefit obligation for each retired member, surviving spouse, beneficiary and terminated vested member was calculated as the actuarial present value of their respective benefits, according to the actuarial assumptions shown in Appendix A.

The current service cost for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits in respect of service in the current year.

Post-Retirement Benefits Other Than Pensions

Prospective benefits were calculated for each active and disabled member according to the actuarial assumptions shown in Appendix A. The projected benefit obligation for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits multiplied by the ratio of service prior to the valuation date to the service from date of hire to full eligibility date.

The projected benefit obligation in respect of each retired member and surviving spouse was calculated as the actuarial present value of their respective benefits, according to the actuarial assumptions shown in Appendix A.

The current service cost for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits divided by service from date of hire to full eligibility date. There is no current service cost in respect of active and disabled members who have attained their full eligibility date.

Extrapolations

The projected benefit obligations and current service costs were first determined as at the date of compilation of the membership data, as disclosed in Appendix C. The projected benefit obligations were then extrapolated to the applicable measurement date based on the actuarial assumptions, actual benefit payments, assumed current service costs and the assumption that there have been no experience gains or losses between the date of compilation of the membership data and the measurement date. No formal materiality guidelines were employed in conducting the valuations or the extrapolations.

The projected benefit obligations for the Pension Choices Plan exclude all balances in DC Core accounts and DB Ancillary Accounts. The current service costs for the Pension Choices Plan exclude all contributions allocated to the DC Core accounts.

Accounting Information

Appendix B contains the financial information required in accordance with ASC 715 for the development of the net benefit cost for 2011 and the 2011 year-end financial disclosure information.

Supplementary Information

Asset Allocation of Funded Plans

The registered pension plans are funded arrangements with the following asset allocation:

	Target Allocation	*Actual Allocation*	
		December 31, 2011	*December 31, 2010*
Equity securities			
■ Canadian equity securities	28%	27%	29%
■ U.S. equity securities	14%	14%	14%
■ EAFE equity securities	13%	13%	13%
Debt securities	45%	46%	44%
Cash and other short term	0%	0%	0%
Total	100%	100%	100%

Comments:

- The investment objective is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants.
- Equity securities do not include any common stock of Spectra Energy Transmission.
- The Company's policy is to fund its defined benefit registered pension plans in Canada on an actuarial basis and in accordance with Canadian pension standards legislation in order to accumulate assets sufficient to meet benefit payments.
- There are no assets with respect to the supplemental pension arrangements or the post-retirement benefits other than pensions.

Sensitivity Analysis

In order to assess the volatility of financial information, certain sensitivity tests have been undertaken with respect to the assumptions for the discount rate, the health care cost trend rate and the expected rate of return on plan assets. The following tables disclose the financial effects resulting from a 1% increase and 1% decrease to each of the indicated assumptions:

US Reporting – All Companies

	Registered Pension Plans and Supplemental Pension Arrangements		***Post-Retirement Benefits Other than Pensions***	
($000s)	*1% Increase*	*1% Decrease*	*1% Increase*	*1% Decrease*
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

Canadian Reporting – All Companies

($000s)	***Registered Pension Plans and Supplemental Pension Arrangements***		***Post-Retirement Benefits Other than Pensions***	
	1% Increase	*1% Decrease*	*1% Increase*	*1% Decrease*
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

Canadian Reporting – Union Gas Limited Only

	Registered Pension Plans and Supplemental Pension Arrangements		***Post-Retirement Benefits Other than Pensions***	
($000s)	*1% Increase*	*1% Decrease*	*1% Increase*	*1% Decrease*
Discount rate				
■ 2011 employer current service cost	$ (2,328)	$ 2,764	$ (392)	$ 492
■ 2011 interest cost	1,824	(2,880)	133	(257)
■ Amortization of net actuarial (gain) loss in 2011	(6,091)	6,835	(424)	481
■ 2011 net periodic benefit cost	(6,595)	6,719	(683)	716
■ Obligation at 2011 fiscal year-end	$ (85,851)	$ 96,937	$ (9,836)	$ 11,119
Health care cost trend rate				
■ 2011 employer current service cost	N/A	N/A	$ 314	$ (270)
■ 2011 interest cost	N/A	N/A	351	(307)
■ Amortization of net actuarial (gain) loss in 2011	N/A	N/A	322	(282)
■ 2011 net periodic benefit cost	N/A	N/A	$ 1,014	$ (859)
■ Projected benefit obligation at 2011 fiscal year-end	N/A	N/A	$ 8,011	$ (6,943)
Expected rate of return on plan assets				
■ 2011 net periodic benefit cost	$ (4,889)	$ 4,889	N/A	N/A

Comment:

- The financial effects shown above with respect to changes to the health care cost trend rate assume that no changes are made to the trend rates for dental care benefits, provincial medical plan premiums or the health care spending account.

Actuarial Opinion – US Reporting

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Actuarial Opinion – Canadian Reporting

The calculations presented in this report have been made in accordance with Section 715 of the Accounting Standards Codification, with which we are familiar. The assumptions used for the calculations, other than the discount rates, were determined by Company management as being their best estimate of long-term expectations, after discussions with Towers Watson. Given that the assumptions were selected by management as representing their best estimates of future contingent events, the valuations are not intended to include any provision for adverse deviations. Towers Watson's opinion is that these assumptions are in accordance with accepted actuarial practice in Canada.

The discount rates used to determine the projected benefit obligations and net benefit costs were determined by Company management based on AA corporate bond yields:

- as at December 31, 2010 for determining the 2011 net benefit costs; and
- as at December 31, 2011 for determining the projected benefit obligations as at the 2011 fiscal year-end.

In our opinion, for the purposes of determining the required accounting information, the data on which the valuations are based are sufficient and reliable, and the methods employed are in accordance with the requirements of Section 715 of the Accounting Standards Codification.

We are not aware of any matter or events expected to occur after the date of this opinion which have not been accounted for and which materially affect the financial position of the plans at the valuation date. However, emerging experience differing from the assumptions will result in gains and losses which will be revealed in future valuations.

This report has been prepared, and this actuarial opinion has been given, in accordance with accepted actuarial practice. This opinion forms an integral part of the report.

Towers Watson Canada Inc.

Stephen J. Butterfield, FCIA (in respect of all covered benefits)	January 27, 2012 Date
David C. McGowan, FCIA (in respect of pension plans only)	January 27, 2012 Date
Bernard Mercier, FCIA (in respect of post-retirement benefits other than pensions only)	January 27, 2012 Date

Actuarial Assumptions

	2011 Net Benefit Cost	*2011 Year-End Obligation*
Economic Assumptions (per annum)		
Discount rate:		
■ Registered pension plans and supplemental pension arrangements	5.25%	4.30%
■ Post-retirement benefits other than pensions	5.31%	4.33%
Rate of compensation increases	3.25%	Same
Rate of increase in YMPE and Income Tax Act maximum pension limit	2.75%	Same
Expected rate of return on plan assets	7.00%	N/A
Extended health care cost trend rate:		
■ Initial rate	8.00%	7.50%
■ Year initial rate is applicable	2010	2011
■ Annual rate of decline	0.50%	Same
■ Ultimate rate	5.00%	Same
■ Year that rate reaches the ultimate trend rate	2017	2017
Rate of dental care inflation	5.00%	Same
Rate of increases in MSP premiums		
[redacted]	[redacted]	[redacted]
Demographic Assumptions		
Mortality	90% of 1994 Uninsured Pensioner Mortality Table projected generationally using Scale AA	Same
Withdrawal	Age related rates (see Table 1)	Same
Retirement	Age and service related rates (see Table 2)	Same
Disability	Nil	Same

Assumed Claims Costs	*2011 Net Benefit Cost*	*2011 Year-End Obligation*
Extended health care costs (per month for single coverage – under 65 / over 65)		
■ Grandfathered Plans:		
— Westcoast members	[redacted]	[redacted]
— Centra Salaried members	$ 143 / $ 67	$ 154 / $ 72
— USWA & CEP North members	$ 114 / N/A	$ 123 / N/A
— Union Gas members	$ 135 / $ 45	$ 146 / $ 49
■ Common Plan:		
— Westcoast members	[redacted]	[redacted]
— Union Gas / St. Clair Pipelines members	$ 68 / $ 24	$ 73 / $ 26
Spending accounts (per annum)		
■ Retiree Supplemental Health Services Plan (single / married):		
— Management & Supervisory members	$ 75 / $150	Same
— Other members	$ 50 / $100	Same
■ Health care spending account (under 65 / 65+)	$1,500 / $1,200	Same
BC Medical Services Plan premiums (per month)		
■ Single / married	[redacted]	[redacted]
Dental care benefits (per month)		
■ Westcoast members	[redacted]	[redacted]
■ Union Gas members	$ 46	$ 48
Load for administrative expenses and taxes		
■ Basic life insurance		
— Member residing in Ontario	12.59%	Same
— All other members	[redacted]	[redacted]
■ Extended health care benefits:		
— Members residing in Ontario	13.91%	Same
— All other members	[redacted]	[redacted]
■ Health care spending account and RSHSP:		
— Members residing in Ontario	13.91%	Same
— All other members	[redacted]	[redacted]

	2011 Net Benefit Cost	2011 Year-End Obligation
■ Dental care benefits:		
— Members residing in Ontario	14.30%	Same
— All other members	[redacted]	[redacted]
■ Stop-loss pooling for extended health care benefits (per month):		
— Single	$1.19	Same
— Family	$2.24	Same
■ ManuAssist for extended health care benefits (per month):		
— Single	$0.25	Same
— Family	$0.50	Same
Percent of spending account forfeited:		
■ Retiree Supplemental Health Services Plan	40%	Same
■ Health care spending account	15%	Same

Other Assumptions

	2011 Net Benefit Cost	2011 Year-End Obligation
Proportion of employees with eligible spouses:		
■ Current retirees		
— Pension arrangements	Current marital status	Same
— Post-retirement benefits other than pensions	80%	Same
■ Future retirees		
— Pension arrangements	90%	Same
— Post-retirement benefits other than pensions	80%	Same
Age difference between spouses	Males 3 years older than females	Same
Rate of interest on member contributions	4.00%	Same
Expenses	Expected rate of return on plan assets is net of all expenses	Same

Comments:

- Details with respect to the development of the initial per capita claims costs and the assumed rates of retirement and rates of termination of employment may be found in the report on the actuarial valuation of post-retirement benefits other than pensions as at December 31, 2008.
- For the 2011 net benefit cost, all claims costs (including extended health care, dental care and MSP premiums) reflect the expected rates in 2011. For the 2011 year-end obligation, all claims costs reflect the expected rates in 2012.
- The assumed claims costs for extended health care have been projected from the initial claims costs developed for the actuarial valuation as at December 31, 2008, assuming increases of 9.0% in 2009, 8.5% in 2010 and 8.0% in 2011.

Table 1 – Withdrawal Rates – Sample Rates

Age	*Rates*
20	0.080
25	0.060
30	0.040
35	0.035
40	0.030
45	0.020
50	0.010
55+	0.000

Table 2 – Retirement Rates

Table 2A – For Employees who Participate in a Registered Pension Plan with Unreduced Retirement at 85 Points

	Service										
Age	*0-20*	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30+*
55	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.150
56	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.150	0.200
57	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.200	0.100	0.200
58	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.300	0.100	0.100	0.250
59	0.050	0.100	0.100	0.100	0.100	0.100	0.300	0.150	0.150	0.150	0.250
60	0.100	0.100	0.100	0.100	0.100	0.350	0.250	0.250	0.250	0.250	0.300
61	0.100	0.100	0.100	0.100	0.350	0.200	0.200	0.200	0.200	0.200	0.200
62	0.350	0.350	0.350	0.350	0.200	0.200	0.200	0.200	0.200	0.200	0.200
63	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
64	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
65	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Table 2B – For Employees who Participate in a Registered Pension Plans with Unreduced Retirement at 90 Points

	Service										
Age	*0-25*	*26*	*27*	*28*	*29*	*30*	*31*	*32*	*33*	*34*	*35+*
55	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.150
56	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.150	0.200
57	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.200	0.100	0.200
58	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.300	0.100	0.100	0.250
59	0.050	0.100	0.100	0.100	0.100	0.100	0.300	0.150	0.150	0.150	0.250
60	0.100	0.100	0.100	0.100	0.100	0.350	0.250	0.250	0.250	0.250	0.300
61	0.100	0.100	0.100	0.100	0.350	0.200	0.200	0.200	0.200	0.200	0.200
62	0.350	0.350	0.350	0.350	0.200	0.200	0.200	0.200	0.200	0.200	0.200
63	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
64	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
65	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - US REPORTING
ALL BUSINESS UNITS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - US REPORTING
ALL BUSINESS UNITS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
ALL BUSINESS UNITS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
ALL BUSINESS UNITS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - PIPELINE

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]				

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - PIPELINE

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - CORPORATE

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - CORPORATE

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - EMPRESS

	Registered Pension Plan	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]				

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - EMPRESS

	Registered Pension Plan	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - SEMC

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	

[redacted]

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
WESTCOAST - SEMC

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
UNION GAS - REGISTERED PENSION PLANS

	Registered Pension Plans						
	M&S Plan	Centra Salaried Plan	Bargaining Unit Plan	Group One Plan	Group Three Plan	Pension Choices Plan	All Plans
2011 Net Periodic Benefit Cost							
Employer current service cost	1,515	552	1,283	71	65	7,940	11,426
Interest cost	7,134	2,796	6,895	409	427	13,892	31,553
Expected return on plan assets	(8,127)	(2,791)	(7,030)	(428)	(450)	(15,403)	(34,229)
Amortization:							
- Net actuarial (gain) loss	4,990	1,891	4,490	345	370	8,177	20,263
- Prior service cost (credit)	78	458	50	115	205	630	1,536
- Transition (asset) liability	0	0	0	0	0	0	0
Total 2011 net periodic benefit cost	5,590	2,906	5,688	512	617	15,236	30,549
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income							
Current year actuarial (gain) loss	25,206	10,586	22,107	1,812	1,940	63,858	125,509
Amortization of actuarial gain (loss)	(4,990)	(1,891)	(4,490)	(345)	(370)	(8,177)	(20,263)
Current year prior service cost (credit)	0	0	0	0	0	0	0
Amortization of prior service (cost) credit	(78)	(458)	(50)	(115)	(205)	(630)	(1,536)
Amortization of transition asset (liability)	0	0	0	0	0	0	0
Total recognized in other comprehensive income	20,138	8,237	17,567	1,352	1,365	55,051	103,710
Total recognized in net periodic cost and other comprehensive income	25,728	11,143	23,255	1,864	1,982	70,287	134,259
Change in Benefit Obligation							
Obligation, beginning of period	139,339	54,654	134,677	7,955	8,336	264,215	609,176
Service cost	1,515	552	1,283	71	65	7,940	11,426
Participant contributions	269	0	383	24	17	2,352	3,045
Interest cost	7,134	2,796	6,895	409	427	13,892	31,553
Benefits paid	(7,930)	(3,340)	(8,304)	(483)	(544)	(9,330)	(29,931)
Prior service cost	0	0	0	0	0	0	0
Actuarial (gains) losses	16,220	7,502	14,515	1,234	1,341	46,513	87,325
Obligation, end of period	156,547	62,164	149,449	9,210	9,642	325,582	712,594
Change in Fair Value of Plan Assets							
Fair value of plan assets, beginning of period	127,196	43,630	110,578	6,671	7,017	234,462	529,554
Actual return on plan assets	(859)	(293)	(562)	(150)	(149)	(1,942)	(3,955)
Employer contributions	7,694	11,977	23,035	1,462	1,665	41,862	87,695
Participant contributions	269	0	383	24	17	2,352	3,045
Benefits paid	(7,930)	(3,340)	(8,304)	(483)	(544)	(9,330)	(29,931)
Fair value of plan assets, end of period	126,370	51,974	125,130	7,524	8,006	267,404	586,408
Reconciliation of Funded Status							
Funded status	(30,177)	(10,190)	(24,319)	(1,686)	(1,636)	(58,178)	(126,186)
Unrecognized net actuarial (gain) loss	72,371	29,064	65,836	5,097	5,458	142,351	320,177
Unrecognized prior service cost (credit)	363	3,533	314	810	607	3,990	9,617
Unrecognized transition (asset) liability	0	0	0	0	0	0	0
Pre-funded (accrued) benefit cost as at December 31, 2011	42,557	22,407	41,831	4,221	4,429	88,163	203,608
(Accrual for Pension) / Deferred Charge							
Pre-funded (accrued) benefit cost as at January 1, 2011	40,453	13,336	24,484	3,271	3,381	61,537	146,462
Net periodic benefit cost	(5,590)	(2,906)	(5,688)	(512)	(617)	(15,236)	(30,549)
Funding contribution	7,694	11,977	23,035	1,462	1,665	41,862	87,695
Pre-funded (accrued) benefit cost as at December 31, 2011	42,557	22,407	41,831	4,221	4,429	88,163	203,608
Expected Average Remaining Service Lifetime (EARSL)	10	10	10	10	10	10	

Note: All amounts are shown in thousands of Canadian dollars.

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
UNION GAS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
2011 Net Periodic Benefit Cost				
Employer current service cost	11,426	389	1,993	13,808
Interest cost	31,553	1,454	3,616	36,623
Expected return on plan assets	(34,229)	0	0	(34,229)
Amortization:				
- Net actuarial (gain) loss	20,263	413	588	21,264
- Prior service cost (credit)	1,536	0	0	1,536
- Transition (asset) liability	0	0	0	0
Total 2011 net periodic benefit cost	30,549	2,256	6,197	39,002
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income				
Current year actuarial (gain) loss	125,509	4,833	9,648	139,990
Amortization of actuarial gain (loss)	(20,263)	(413)	(588)	(21,264)
Current year prior service cost (credit)	0	0	0	0
Amortization of prior service (cost) credit	(1,536)	0	0	(1,536)
Amortization of transition asset (liability)	0	0	0	0
Total recognized in other comprehensive income	103,710	4,420	9,060	117,190
Total recognized in net periodic cost and other comprehensive income	134,259	6,676	15,257	156,192
Change in Benefit Obligation				
Obligation, beginning of period	609,176	28,120	68,401	705,697
Service cost	11,426	389	1,993	13,808
Participant contributions	3,045	0	0	3,045
Interest cost	31,553	1,454	3,616	36,623
Benefits paid	(29,931)	(1,324)	(2,786)	(34,041)
Prior service cost	0	0	0	0
Actuarial (gains) losses	87,325	4,833	9,648	101,806
Obligation, end of period	712,594	33,472	80,872	826,938
Change in Fair Value of Plan Assets				
Fair value of plan assets, beginning of period	529,554	0	0	529,554
Actual return on plan assets	(3,955)	0	0	(3,955)
Employer contributions	87,695	1,324	2,786	91,805
Participant contributions	3,045	0	0	3,045
Benefits paid	(29,931)	(1,324)	(2,786)	(34,041)
Fair value of plan assets, end of period	586,408	0	0	586,408
Reconciliation of Funded Status				
Funded status	(126,186)	(33,472)	(80,872)	(240,530)
Unrecognized net actuarial (gain) loss	320,177	13,020	26,478	359,675
Unrecognized prior service cost (credit)	9,617	0	0	9,617
Unrecognized transition (asset) liability	0	0	0	0
Pre-funded (accrued) benefit cost as at December 31, 2011	203,608	(20,452)	(54,394)	128,762
(Accrual for Pension) / Deferred Charge				
Pre-funded (accrued) benefit cost as at January 1, 2011	146,462	(19,520)	(50,983)	75,959
Net periodic benefit cost	(30,549)	(2,256)	(6,197)	(39,002)
Funding contribution	87,695	1,324	2,786	91,805
Pre-funded (accrued) benefit cost as at December 31, 2011	203,608	(20,452)	(54,394)	128,762
Expected Average Remaining Service Lifetime (EARSL)	10	14	18	

Note: All amounts are shown in thousands of Canadian dollars.

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
UNION GAS

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
Funded Status	(126,186)	(33,472)	(80,872)	(240,530)
Amounts Recognized in the Statement of Financial Position				
Noncurrent asset	0	0	0	0
Current liability	0	1,327	2,799	4,126
Noncurrent liability	126,186	32,145	78,073	236,404
Net amount recognized	(126,186)	(33,472)	(80,872)	(240,530)
Amounts Recognized in Accumulated Other Comprehensive Income				
Net actuarial (gain) loss	320,177	13,020	26,478	359,675
Prior service cost (credit)	9,617	0	0	9,617
Transition liability (asset)	0	0	0	0
Net amount recognized	329,794	13,020	26,478	369,292
Reconciliation of Accumulated Other Comprehensive Income				
AOCI as at January 1, 2011	226,084	8,600	17,418	252,102
Other comprehensive income recognized	103,710	4,420	9,060	117,190
AOCI as at December 31, 2011	329,794	13,020	26,478	369,292
Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets				
Projected benefit obligation	712,594	33,472	N/A	746,066
Accumulated benefit obligation	664,334	31,470	N/A	695,804
Fair value of plan assets	586,408	0	N/A	586,408
Expected Cash Flows				
Expected employer contributions (funded plans)				
2012	63,758	N/A	N/A	63,758
Expected benefit payments				
2012	31,319	1,327	2,799	35,445
2013	33,108	1,332	2,975	37,415
2014	34,908	1,336	3,153	39,397
2015	36,532	1,339	3,342	41,213
2016	37,961	1,346	3,542	42,849
2017-2021	204,216	7,029	17,710	228,955
Estimated Amounts that will be Amortized from Accumulated Other Comprehensive Income into Net Periodic Cost in 2012				
Net actuarial (gain) loss	25,312	691	1,022	27,025
Prior service cost (credit)	1,536	0	0	1,536
Transition liability (asset)	0	0	0	0
Total	26,848	691	1,022	28,561

Note: All amounts are shown in thousands of Canadian dollars.

SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
ST. CLAIR PIPELINES

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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SPECTRA ENERGY TRANSMISSION - CANADA
ASC 715 ACCOUNTING INFORMATION FOR 2011 - CANADIAN REPORTING
ST. CLAIR PIPELINES

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits other than Pensions	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Membership Data

Our calculations are based on membership data compiled as at the following dates:

Plan	*2011 Net Benefit Cost*	*2011 Year-End Obligation*
Registered pension plans	January 1, 2010	January 1, 2011
SRCAs and executive arrangements	September 30, 2010	September 30, 2011
SEMPL	January 1, 2010	January 1, 2011
Post-retirement benefits other than pensions	January 1, 2009	January 1, 2009

Review of Membership Data

Membership data were supplied by the Company's third party administrator, ACS Consulting, a Xerox Company, as at the applicable date.

The membership data was reviewed for reasonableness. Elements of the data review included the following:

- ensuring that the data was intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain that the complete membership of the pension plan was accounted for;
- preparation and review of age and service distributions for active members for reasonableness;
- comparison, for active members, of ages, covered payroll, member contribution account balances and pensionable service to the prior valuation data for reasonableness;
- comparison, for active members, of member contribution data to actual member contribution remittances made to the plan for the period since the prior valuation date;
- comparison, for terminated vested members, of age and deferred pension to the prior valuation data for reasonableness;
- comparison, for retired members and beneficiaries, of age and pension payments to the prior valuation data for reasonableness; and
- comparison of pension payments to actual payments made from the plan for the period prior to the valuation date.

The membership data is considered to be complete and sufficient and reliable for the purposes of preparing the financial information contained in this report.

Towers Watson does not take responsibility for the membership data.

Summary of Membership Data – Pension Choices Plan (DB Only)

	January 1, 2011	January 1, 2010
Active and disabled members:		
■ Number	1,304	1,253
■ Average age	46.9	47.2
■ Average credited service	14.7	15.3
■ Average covered payroll	$ 83,207	$ 81,510
Retired members, surviving spouses and beneficiaries:		
■ Number	513	487
■ Average age	69.6	69.3
■ Average annual lifetime pension	$ 16,913	$ 16,070
Terminated vested members:		
■ Number	73	66
■ Average age	50.3	49.8
■ Average annual pension	$ 11,295	$ 11,767

[redacted]

Summary of Membership Data – M&S Plan

		January 1, 2011		January 1, 2010
Active and disabled members:				
■ Number		102		114
■ Average age		55.5		55.0
■ Average credited service		28.5		27.7
■ Average covered payroll	$	100,141	$	98,110
Retired members, surviving spouses and beneficiaries:				
■ Number		336		332
■ Average age		75.0		74.6
■ Average annual lifetime pension	$	23,140	$	22,547
Terminated vested members:				
■ Number		11		10
■ Average age		55.5		54.5
■ Average annual pension	$	17,942	$	19,122

Summary of Membership Data – Bargaining Unit Plan

		January 1, 2011		January 1, 2010
Active and disabled members:				
■ Number		168		190
■ Average age		55.8		55.3
■ Average credited service		28.3		27.6
■ Average covered payroll	$	65,628	$	63,805
Retired members, surviving spouses and beneficiaries:				
■ Number		528		517
■ Average age		72.7		72.4
■ Average annual lifetime pension	$	13,432	$	12,977
Terminated vested members:				
■ Number		6		6
■ Average age		49.7		48.7
■ Average annual pension	$	5,842	$	5,842

Summary of Membership Data – Centra Salaried Plan

	January 1, 2011	January 1, 2010
Active and disabled members:		
■ Number	44	49
■ Average age	53.9	53.8
■ Average credited service	28.8	28.6
■ Average covered payroll	$ 91,054	$ 88,013
Retired members and beneficiaries:		
■ Number	189	190
■ Average age	72.3	71.7
■ Average annual lifetime pension	$ 16,491	$ 15,921
Terminated vested members:		
■ Number	66	68
■ Average age	53.8	52.7
■ Average annual pension	$ 3,641	$ 3,669

Summary of Membership Data - Group One Plan

	January 1, 2011	January 1, 2010
Active members:		
■ Number	11	10
■ Average age	50.7	51.2
■ Average credited service	20.6	20.2
■ Average covered payroll	$ 56,448	$ 54,140
Disabled members:		
■ Number	3	3
■ Average age	55.5	54.5
■ Average credited service	25.2	23.5
Retired members, surviving spouses and beneficiaries:		
■ Number	51	52
■ Average age	70.1	69.7
■ Average annual lifetime pension	$ 8,374	$ 8,358
Terminated vested members:		
■ Number	25	25
■ Average age	51.7	50.7
■ Average annual pension	$ 3,560	$ 3,560

Summary of Membership Data - Group Three Plan

	January 1, 2011	January 1, 2010
Active members:		
■ Number	8	8
■ Average age	53.5	50.0
■ Average credited service	22.8	21.0
■ Average covered payroll	$ 61,908	$ 60,481
Disabled members:		
■ Number	3	4
■ Average age	57.8	58.0
■ Average credited service	28.6	26.7
Retired members, surviving spouses and beneficiaries:		
■ Number	57	55
■ Average age	72.2	71.5
■ Average annual lifetime pension	$ 8,863	$ 8,894
Terminated vested members:		
■ Number	37	38
■ Average age	49.6	49.0
■ Average annual pension	$ 2,014	$ 2,007

Summary of Membership Data – Supplemental Pension Arrangements

	September 30, 2011	September 30, 2010
Active and disabled members:		
■ Number	19	19
■ Average age	52.9	51.9
■ Average credited service	14.2	13.3
■ Average covered payroll	$ 395,000	$ 377,552
Retired members, surviving spouses and beneficiaries:		
■ Number	94	90
■ Average age	67.5	67.0
■ Average annual lifetime pension	$ 63,238	$ 63,356
Terminated vested members:		
■ Number	6	7
■ Average age	55.9	54.8
■ Average annual pension	$ 57,183	$ 81,017

Comments:

- The membership data shown above for active and disabled members is in respect of the SRCAs and the Executive Arrangements only. All active members of any registered pension plan are automatically members of the SEMPL and will receive benefits under the SEMPL if their benefits under the registered pension plan are limited by the Income Tax Act maximum pension limit.

- The membership data shown above for retired members, surviving spouses, beneficiaries and terminated vested members includes membership under the SRCAs, the Executive Arrangements and the SEMPL.

Summary of Membership Data – Post-Retirement Benefits Other Than Pensions

January 1, 2009

	[redacted]	*Union Gas PRBs*	*Centra Salaried PRBs*	*USW & CEP North PRBS*	*Common PRBs*	*Total*
Active and disabled members:						
■ Number	[redacted]	0	0	0	3,153	3,345
■ Average age	[redacted]	N/A	N/A	N/A	46.5	46.4
■ Average service	[redacted]	N/A	N/A	N/A	16.4	16.2
Retired members and surviving spouses:						
■ Number	[redacted]	924	142	80	194	1,796
■ Average age	[redacted]	73.0	70.9	70.4	61.2	70.8

Summary of Plan Provisions

Pension Choices Plan – DB Provision

The following is an outline of the principal features of the plan which are of financial significance to valuing the defined benefit provisions of the Pension Choices Plan. For a detailed description of the benefits, please refer to the plan document.

Recent Amendments

The plan was amended effective April 1, 2011 to remove the cap on the pensionable Northern Allowance for members affiliated with the Canadian Pipeline Employees' Association ("CPEA") and for members employed by SEMC. The elimination of the cap on the pensionable Northern Allowance is on a prospective basis only.

Structure of the Plan

There are four distinct provisions of the plan, namely the Grandfathered Plan, DB Core, DB Buy-up and DC Core. Each active member of the plan accrues benefits under only one of these provisions.

Definitions

a) Continuous Service

Years of employment with a related employer.

b) Credited Service

The sum of Credited Grandfathered Service and Credited Choices Service.

c) DB Buy-up

A contributory defined benefit provision of the plan.

d) DB Core

A non-contributory defined benefit provision of the plan.

e) DC Core

A defined contribution provision of the plan.

f) Grandfathered Plan

The contributory defined benefit provision of the plan in effect prior to the introduction of the new plan provisions on July 1, 1999.

g) Legacy Plan

Any one of the following registered pension plans:

i) Westcoast Plan;

ii) Management & Supervisory Plan;

iii) Centra Salaried Plan;

iv) Bargaining Unit Plan;

v) Group One Plan; or

vi) Group Three Plan.

h) Northern Allowance

Additional annual compensation paid to members as a result of working in a remote location.

i) Northern Allowance Effective Date

January 1, 2006: For employees of Westcoast affiliated with the Canadian Pipeline Employees' Association ("CPEA").

January 1, 2007: For non-union employees of Westcoast and SEMC.

Eligibility

Permanent non-union employees of a participating employer and permanent unionized employees of a participating employer whose collective agreement provides for participation in the plan are required to join the plan effective on their date of hire and all temporary employees of a participating employer are required to join the plan upon satisfying the minimum statutory eligibility conditions.

Participation in the Provisions of the Plan

- Each person who was a member of the plan prior to July 1, 1999 was required to make a one-time election, effective July 1, 1999, to accrue future benefits under the Grandfathered Plan, DB Core, DB Buy-up or DC Core.
- Each person who was a member of a Legacy Plan prior to being eligible to join the plan was required to make a one-time election, effective on the date of being eligible to join the plan to remain a member of such Legacy Plan or to become a member of the plan and to accrue future benefits under DB Core, DB Buy-up or DC Core.
- Executives are required to become members of DB Buy-up.
- Members who elected to accrue future benefits under DC Core were provided with a lump sum Initial Account Value equal to the value of the benefits earned under the plan or the respective Legacy Plan for service prior to the date of joining the plan.
- Members who elected to accrue future benefits under DB Core or DB Buy-up will have their benefits in respect of service prior to joining the plan determined in accordance with the Legacy Plan or the Grandfathered Plan, as applicable. Any benefits payable under the terms of a Legacy Plan will be paid from the plan.
- Members who join the plan after the applicable effective date for their employee group must make a one-time election to accrue all benefits under DB Core, DB Buy-up or DC Core.

Grandfathered Plan

Definitions

a) *Accrued Grandfathered Pension*

1.3% of Final Average YMPE plus 1.65% of the excess, if any, of Final Average Grandfathered Earnings over Final Average YMPE, multiplied by Credited Grandfathered Service.

b) *Credited Grandfathered Service*

Years of service during which a member makes required contributions to the Grandfathered Plan, unless such contributions are waived due to disability.

c) *Final Average Grandfathered Earnings*

Annual average of Grandfathered Earnings over the 36 consecutive calendar months in which such average is the highest.

d) *Final Average YMPE*

The annual average of the YMPE calculated over the same 36 consecutive calendar months as used in determining Final Average Grandfathered Earnings.

e) *Grandfathered Earnings*

Base earnings including any applicable STIP payments, but exclusive of overtime and other exceptional forms of compensation.

f) *YMPE*

Year's Maximum Pensionable Earnings, as defined under the Canada Pension Plan.

Member Grandfathered Contributions

Members are required to contribute, in each year, an amount equal to 3.5% of Grandfathered Earnings up to the YMPE, plus 5.0% of Grandfathered Earnings, if any, in excess of the YMPE.

Normal Retirement

a) *Date*

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) *Annual Pension*

Accrued Grandfathered Pension at the Normal Retirement Date.

Early Retirement

a) *Date*

First day of any month following attainment of age 55 or completion of 30 years of Credited Service ("Early Retirement Date").

b) *Annual Pension*

Accrued Grandfathered Pension at the Early Retirement Date reduced by:

(i) 0.25% for each month by which the Early Retirement Date precedes attainment of age 62; plus

(ii) 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 60.

No reduction applies if age plus Credited Grandfathered Service totals at least 90 years.

c) *Supplemental Pension*

1/35 of $400 for each year of Credited Grandfathered Service (maximum 35) payable from the Early Retirement Date to the Normal Retirement Date.

Postponed Retirement

a) *Date*

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) *Annual Pension*

Accrued Grandfathered Pension at the Postponed Retirement Date.

Termination of Employment

a) *Annual Pension*

Accrued Grandfathered Pension payable at the Normal Retirement Date.

b) *Minimum Pension in Respect of Credited Service Prior to January 1, 1987*

Monthly pension which is the actuarial equivalent of the required member contributions with interest in respect of Credited Grandfathered Service accrued prior to January 1, 1987.

c) *Additional Benefit*

Refund of member contributions with interest in respect of Credited Grandfathered Service accrued on or after January 1, 1987 which are in excess of 50% of the value of benefits accrued in respect of such Credited Grandfathered Service.

Pre-Retirement Death Benefits

For Credited Grandfathered Service prior to January 1, 1987: Refund of required member contributions with interest.

For Credited Service on or after January 1, 1987: The sum of the actuarial equivalent of the Accrued Grandfathered Pension accrued to the date of death, and the refund of required member contributions with interest which are in excess of 50% of the value of benefits accrued in respect of such Credited Grandfathered Service.

Form of Pension

The normal form of pension payment provides for a refund of required member contributions with interest to the retirement date that are in excess of the aggregate pension payments received by the member. Members may choose from a number of available optional forms of payment on an actuarial equivalent basis.

Disability Benefits

Upon total and permanent disability prior to the Normal Retirement Date, required member contributions cease and Credited Grandfathered Service continues to accrue until the earlier of the return to employment and age 65.

Adjustment to Pensions in Course of Payment

There are no automatic adjustments to pensions in course of payment. Ad hoc increases have been provided in the past. The last ad hoc increase was granted effective January 1, 2001.

DB Core and DB Buy-up

Definitions

a) *Accrued Choices Pension*

The sum of:

(i) 1.0% of Final Average Choices Earnings multiplied by Credited Choices Service while accruing benefits under DB Core.

(iii) 2.0% of Final Average Choices Earnings multiplied by Credited Choices Service while accruing benefits under DB Buy-up.

b) *Ancillary Benefits*

Additional benefits purchased with accumulated amounts in a member's DB Ancillary Account.

c) *Choices Earnings*

Base earnings including any applicable Northern Allowance and STIP payments, but exclusive of overtime and other exceptional forms of compensation. STIP payments are assumed to be earned evenly over the calendar year following the date of payment.

d) *Credited Choices Service*

Period of service while earning benefits under DB Core or DB Buy-up.

e) *DB Ancillary Account*

The individual account established for each member accruing benefits under DB Core or DB Buy-up, to which voluntary contributions are deposited and from which Ancillary Benefits are purchased.

f) *Final Average Choices Earnings*

Annual average of Choices Earnings over the 36 consecutive calendar months in which such average is the highest.

g) *Pension Credit*

For employees hired prior to January 1, 2004, the Pension Credit is:

(i) 1.75% of Choices Earnings for employees of Westcoast;

(ii) 0.5% of Choices Earnings for management and supervisory employees of Union Gas and former salaried employees of Centra Gas Inc.; and

(iii) 0.0% for other employees.

The Pension Credit is 0.0% for all employees hired on or after January 1, 2004.

Required Member Contributions

Members of DB Buy-up are required to contribute 5.0% of Choices Earnings less the Pension Credit. Executives and members accruing benefits under DB Core are not required to make any member contributions to the plan.

Normal Retirement

a) *Date*

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) *Annual Pension*

Accrued Choices Pension at the Normal Retirement Date.

Early Retirement

a) *Date*

First day of the month following attainment of age 55 ("Early Retirement Date").

b) *Annual Pension*

Accrued Choices Pension at the Early Retirement Date reduced by 0.25% for each month by which the Early Retirement Date precedes attainment of age 62. No reduction applies if age plus Continuous Service totals at least 85 years.

Postponed Retirement

a) *Date*

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) *Annual Pension*

Accrued Choices Pension at the Postponed Retirement Date.

Termination of Employment

a) *Vesting*

2 years of Continuous Service after becoming a member of the plan or a Legacy Plan.

b) *Non-Vested Termination of Employment*

A member who terminates employment prior to vesting is entitled to a refund of required member contributions, if any, with interest.

c) *Annual Pension Upon Vested Termination of Employment*

A member who terminates employment following vesting is entitled to an annual pension, payable at the Normal Retirement Date, equal to the Accrued Choices Pension.

d) *Early Retirement*

A member who is entitled to a pension payable at the Normal Retirement Date may elect to commence such pension on the first day of any month following the Early Retirement Date. The pension is reduced by 0.5% per month that the pension commencement date precedes the Normal Retirement Date, but in no event shall the reduction be greater than an actuarial equivalent reduction.

e) *Additional Benefit*

Refund of required member contributions with interest which are in excess of 50% of the value of benefits accrued.

Pre-Retirement Death Benefits

The sum of the actuarial equivalent to the Accrued Choices Pension accrued to date of death, and the refund of required member contributions with interest which are in excess of 50% of the value of benefits accrued.

Form of Pension

The normal form of pension payment provides for a guarantee that 120 monthly payments will be made to the member and beneficiary combined. Members may elect a different form of payment on an actuarial equivalent basis. However, if a member is also entitled to a benefit under a Legacy Plan or the Grandfathered Plan, the member must elect the same form of pension under both components of the plan.

Disability

a) *Members of DB Core*

Upon total and permanent disability prior to the Normal Retirement Date, Credited Choices Service continues to accrue until the earlier of the return to employment and age 65.

b) *Members of DB Buy-up*

Upon total and permanent disability prior to the Normal Retirement Date, the member must elect either:

(i) to continue making required member contributions, in which case the member will continue to accrue benefits under DB Buy-up while disabled; or

(ii) to cease making required member contributions, in which case the member will accrue benefits under DB Core while disabled.

A member who elects to accrue benefits under DB Core during a period of disability and who subsequently ceases to be disabled and returns to active employment shall make a one-time election as to whether to accrue future benefits under DB Core or DB Buy-up.

Westcoast Plan

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Management & Supervisory Plan

The following is an outline of the principal features of the plan which are of financial significance to valuing the benefits under the M&S Plan. For a detailed description of the benefits, please refer to the plan document.

Definitions

a) Accrued Pension

The vast majority of Credited Service recognized under the plan is Credited Supervisory Service to which the following formula applies:

(i) 1.3% of Final Average YMPE plus 1.75% of the excess, if any, of Final Average Earnings over Final Average YMPE, multiplied by Credited Service accrued on or after January 1, 1975;

(ii) 1.75% of Final Average Earnings, multiplied by Credited Service accrued prior to January 1, 1975.

b) Continuous Service

Years of employment with the company or a related employer.

c) Credited Service

Years of service during which a member either makes required contributions to the plan or is disabled.

d) Earnings

Base earnings including any applicable STIP bonuses, but exclusive of overtime and other exceptional forms of compensation.

e) Final Average Earnings

Annual average of Earnings over the 36 consecutive calendar months in which such average is the highest.

f) Final Average YMPE

The annual average of the YMPE calculated over the same 36 consecutive calendar months as used in determining Final Average Earnings.

g) YMPE

Year's Maximum Pensionable Earnings, as defined under the Canada Pension Plan.

Eligibility

Effective January 1, 1999, no person is eligible to join the plan.

Member Contributions

Members are required to contribute, in each year, an amount equal to 5.0% of Earnings, if any, in excess of the YMPE.

Normal Retirement

a) Date

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) Annual Pension

Accrued Pension at the Normal Retirement Date.

Early Retirement

a) Date

First day of any month following attainment of age 55 or completion of 30 years of Credited Service ("Early Retirement Date").

b) Annual Pension

Accrued Pension at the Early Retirement Date reduced by:

(i) 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 62; plus

(ii) 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 60.

No reduction applies if age plus Credited Service totals at least 90 years.

c) Supplemental Pension

1/35 of $400 for each year of Credited Service (maximum 35) payable from the Early Retirement Date to the Normal Retirement Date.

Postponed Retirement

a) Date

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) Annual Pension

Accrued Pension at the Postponed Retirement Date.

Termination of Employment

a) Annual Pension

Accrued Pension payable at the Normal Retirement Date. Members may elect to receive a pension at any time after the Early Retirement Date, reduced on an actuarial equivalent basis.

b) Minimum Benefit

Refund of required member contributions with interest.

c) Additional Benefit

Refund of member contributions with interest in respect of Credited Service accrued on or after January 1, 1987 which are in excess of 50% the value of benefits accrued in respect of such Credited Service.

Pre-Retirement Death Benefits

a) Benefit

For Credited Service prior to January 1, 1987: Refund of required member contributions with interest.

For Credited Service on or after January 1, 1987: The greater of required member contributions with interest and the lump sum which is the actuarial equivalent of the Accrued Pension at the date of death.

b) Additional Benefit

Refund of required member contributions with interest in respect of Credited Service accrued on or after January 1, 1987 which are in excess of 50% the value of benefits accrued in respect of such Credited Service.

Form of Pension

The normal form of pension payment for a member with no spouse provides for a refund of contributions with interest in excess of the aggregate pension payments received by the member. The normal form of pension payment for a member with a spouse is a joint and 60% survivor annuity. Members may elect a different form of payment on an actuarial equivalent basis.

Disability Benefits

Upon total and permanent disability prior to the Normal Retirement Date, required member contributions cease and Credited Service continues to accrue until the earlier of the return to employment and age 65.

Adjustment to Pensions in Course of Payment

There is no automatic adjustment to pensions in course of payment. Ad hoc increases have been provided in the past. The last ad hoc increase was granted effective January 1, 2001.

Centra Salaried Plan

The following is an outline of the principal features of the plan which are of financial significance to valuing the benefits under the Centra Salaried Plan. For a detailed description of the benefits, please refer to the plan document.

Definitions

a) Accrued Pension

i) For service before January 1, 1986

Former members of the NCG Plan

For each year of Prior Contributory Credited Service:

- 1.15% of Average 5-year Earnings up to the Average 5-year YMPE, plus 1.75% of Average 5-year Earnings in excess of the Average 5-year YMPE.

For each year of Prior Non-contributory Credited Service:

- 0.6% of Average 5-year Earnings up to the Average 5-year YMPE, plus 1.2% of Average 5-year Earnings in excess of the Average 5-year YMPE.

Other members

For each year of Credited Service, the greater of:

- 0.9% of Average 5-Year Earnings up to the Average 5-year YMPE, plus 1.5% of Average 5-year Earnings in excess of the Average 5-year YMPE; and
- 1.2% of Average 10-year Earnings up to the Average 10-year YMPE, plus 2.0% of Average 10-year Earnings in excess of the Average 10 year-YMPE.

Maximum pension

- $1,400 per year of Credited Service.

ii) For service after January 1, 1986

For each year of Credited Service

- 1.0% of Average 5-Year Earnings up to the Average 5-year YMPE, plus 1.5% of Average 5-year Earnings in excess of the Average 5-year YMPE.

b) Average 5-year Earnings

Average of all regular compensation (including commissions and bonuses) for the 60 consecutive months during which such compensation is highest.

c) Average 10-year Earnings

Average of all regular compensation (including commissions and bonuses) for the 120 consecutive months during which such compensation is highest.

d) Average 5-year YMPE

Average of the YMPE over the same period used for the Average 5-year Earnings.

e) Average 10-year YMPE

Average of the YMPE over the same period used for the Average 10-year Earnings.

f) Credited Service

Period of service while a member of the plan.

g) NCG Plan

The Northern and Central Gas Salaried Employees' Pension Plan.

h) Prior Contributory Credited Service

Period of service while a contributory member of the NCG Plan.

i) Prior Non-Contributory Credited Service

Period of service while a non-contributory member of the NCG Plan.

j) YMPE

Year's Maximum Pensionable Earnings under the Canada/Quebec Pension Plan.

Eligibility for Membership

Effective January 1, 1999, no further new members permitted.

Member Contributions

Nil.

Normal Retirement

a) Date

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) Annual Pension

Accrued Pension at the Normal Retirement Date.

Early Retirement

a) Date

First day of the month following attainment of age 55 ("Early Retirement Date").

b) Annual Pension

Accrued Pension at the Early Retirement Date either:

- unreduced if age is greater than or equal to 62 or if age plus continuous service is greater than or equal to 90 years; or
- otherwise reduced by 3% for each year that the member's age at the Early Retirement Date is less than 62.

Postponed Retirement

a) Date

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) Annual Pension

Accrued Pension at the Postponed Retirement Date.

Termination of Employment

Accrued Pension payable at the Normal Retirement Date. Members may elect to receive a pension at any time after the Early Retirement Date, reduced on an actuarial equivalent basis.

Pre-Retirement Death Benefits

The commuted value of the Accrued Pension payable at the Normal Retirement Date or the Early Retirement Date if the member is entitled to early retirement on the date of death.

Form of Payment

For a member without a spouse: 10-year guarantee and life thereafter. For a member with a spouse: 5-year guarantee with 50% of pension in payment payable to spouse for life. Members may elect a different form of payment on an actuarial equivalent basis.

Disability Benefits

Members receiving long-term disability benefits continue to accrue benefits. Earnings at date of disability are assumed to continue unchanged during the period of disability.

Adjustment to Pensions in Course of Payment

There is no automatic adjustment to pension in course of payment. Ad hoc increases have been provided in the past. The last ad hoc increase was granted effective January 1, 2001.

Bargaining Unit Plan

The following is an outline of the principal features of the plan which are of financial significance to valuing the benefits under the Bargaining Unit Plan. For a detailed description of the plan, please refer to the plan document.

Definitions

a) Accrued Pension

1.3% of Final Average Earnings up to the Final Average YMPE plus 1.65% of the excess, if any, of Final Average Earnings over Final Average YMPE, multiplied by Credited Service.

b) Continuous Service

Years of employment with the company.

c) Credited Service

Years of service during which a member makes required contributions to the plan or is disabled.

d) Earnings

Base earnings including any applicable STIP bonuses, but exclusive of overtime and other exceptional forms of compensation.

e) Final Average Earnings

Annual average of Earnings over the 36 consecutive calendar months in which such average is the highest.

f) Final Average YMPE

The annual average of the YMPE calculated over the same 36 consecutive calendar months as used in determining Final Average Earnings.

g) YMPE

Year's Maximum Pensionable Earnings, as defined under the Canada Pension Plan.

Eligibility

Prior to August 1, 2001, full-time employees of the bargaining unit were eligible to join the plan on the first day of any month following the completion of 2 calendar months of Continuous Service.

Effective August 1, 2001, no further employees are eligible to become members of the plan.

Member Contributions

Members are required to contribute, in each year, an amount equal to 3.5% of Earnings up to the YMPE, plus 5.0% of Earnings, if any, in excess of the YMPE.

Normal Retirement

a) Date

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) Annual Pension

Accrued Pension at the Normal Retirement Date.

Early Retirement

a) Date

First day of any month following attainment of age 55 or completion of 30 years of Credited Service ("Early Retirement Date").

b) Annual Pension

Accrued Pension at the Early Retirement Date reduced by:

(i) 0.25% for each month by which the Early Retirement Date precedes attainment of age 62; plus

(ii) 0.25% for each complete month by which the Early Retirement Date precedes the attainment of age 60.

No reduction applies if age plus Credited Service totals at least 90 years.

c) Supplemental Benefit

1/35 of $400 for each year of Credited Service (maximum 35) payable from the Early Retirement Date to the Normal Retirement Date.

Postponed Retirement

a) Date

First day of any month after Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date').

b) Annual Pension

Accrued Pension at the Postponed Retirement Date.

Termination of Employment

a) Annual Pension

Accrued Pension, payable at the Normal Retirement Date. Members may elect to receive a pension at any time after the Early Retirement Date, reduced on an actuarial equivalent basis.

b) Minimum Benefit

Refund of required member contributions with interest.

c) Additional Benefit

Refund of required member contributions with interest in respect of Credited Service accrued on or after January 1, 1987 which are in excess of 50% of the value of benefits accrued in respect of such Credited Service.

Pre-Retirement Death Benefits

a) Benefit

For Credited Service prior to January 1, 1987: Refund of required member contributions with interest.

For Credited Service on or after January 1, 1987: The greater of required member contributions with interest and the lump sum which is the actuarial equivalent of the Accrued Pension at the date of death.

b) Additional Benefit

Refund of required member contributions with interest in respect of Credited Service accrued on or after January 1, 1987 which are in excess of 50% of the value of benefits accrued in respect of such Credited Service.

Form of Pension

The normal form of pension payment provides for a refund of required member contributions with interest in excess of the aggregate pension payments received by the member. Members may elect a different form of payment on an actuarial equivalent basis.

Disability Benefits

Upon total and permanent disability prior to the Normal Retirement Date, required member contributions cease and Credited Service continues to accrue until the earlier of the return to employment and age 65.

Adjustment to Pensions in Course of Payment

There is no automatic adjustment to pensions in course of payment. Ad hoc increases have been provided in the past. The last ad hoc increase was granted effective January 1, 2001.

Group One Plan

The following is an outline of the principal features of the plan which are of financial significance to valuing the benefits under the Group One Plan. For a detailed description of the benefits, please refer to the plan document.

Definitions

a) ***Continuous Service***

Years of employment with the company.

b) ***Credited Service***

The sum of Prior Plan Credited Service and New Plan Credited Service.

c) ***Final Earnings Provision***

The amended provisions of the plan added effective July 1, 2004.

d) ***Flat Dollar Provision***

The provisions of the plan in effect as at June 30, 2004.

e) ***New Plan Credited Service***

Service accrued on and after July 1, 2004, except that if the member was disabled on July 1, 2004, service accrued on and after the date the member ceases to be disabled.

f) ***Prior Plan Credited Service***

Service accrued prior to July 1, 2004, except if the member was disabled on July 1, 2004, service accrued prior to the date the member ceases to be disabled.

Application of Provisions of the Plan

Active and disabled members will have their benefit entitlements determined at the earliest of their date of retirement, date of termination of employment and date of death, as follows:

- benefits in respect of New Plan Credited Service will be determined in accordance with the Final Earnings Provision;
- benefits in respect of Prior Plan Credited Service will be determined as the greater of the actuarial present value of benefits under the Flat Dollar Provision and the actuarial present value of benefits under the Final Earnings Provision.

Eligibility for Membership

Members of the United Steelworkers Local 2020 and 7846.

The plan is closed to new members effective January 1, 2004.

Flat Dollar Provision

Definitions

a) *Accrued Pension:*

Prior Plan Credited Service multiplied by the Benefit Accrual Rate plus any frozen pension benefits previously accrued.

b) *Monthly Benefit Accrual Rate:*

Effective January 1, 2003: $49.50 multiplied by 12.

Member Contributions

Nil.

Normal Retirement

a) *Date*

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) *Annual Pension*

Accrued Pension at the Normal Retirement Date.

Early Retirement

a) *Date*

First day of the month following attainment of age 55 ("Early Retirement Date").

b) *Annual Pension*

Accrued Pension at the Early Retirement Date unreduced if age 62 otherwise reduced by 3% for each year that the member's age at the Early Retirement Date is less than 62.

Postponed Retirement

a) *Date*

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) *Annual Pension*

Accrued Pension at the Postponed Retirement Date.

Termination of Employment

Accrued Pension payable at the Normal Retirement Date. Members may elect to receive a pension at any time after the Early Retirement Date, reduced on an actuarial equivalent basis.

Pre-Retirement Death Benefits

The commuted value of the member's Accrued Pension payable at the Normal Retirement Date or, if the member has attained the Early Retirement Date as of the date of death, the commuted value of the Accrued Pension payable at the Early Retirement Date.

Form of Payment

For a member without a spouse: lifetime pension. For a member with a spouse: 60% of pension in payment payable to spouse for life. Members may elect a different form of payment on an actuarial equivalent basis.

Adjustment to Pensions in Course of Payment

There is no automatic adjustment to pensions in course of payment. Ad hoc increases have been provided in the past. The last ad hoc increase was granted effective January 1, 2001.

Final Earnings Provisions

Benefits must be determined under this Final Earnings Provision both in respect of Prior Plan Credited Service and New Plan Credited Service. For the purposes of this summary of plan provisions, the term "Applicable Credited Service" is used to reflect the Credited Service being referred to, depending on which period of service the benefits are being calculated in respect of.

Definitions

a) *Accrued Pension*

   1.3% of Final Average Earnings up to the Final Average YMPE plus 1.65% of the excess, if any, of Final Average Earnings over Final Average YMPE, multiplied by Applicable Credited Service.

b) *Earnings*

   Base earnings including any applicable STIP bonuses, but exclusive of overtime and other exceptional forms of compensation.

c) *Final Average Earnings*

   Annual average of Earnings over the 36 consecutive calendar months in which such average is the highest.

d) *Final Average YMPE*

   The annual average of the YMPE calculated over the same 36 consecutive calendar months as used in determining Final Average Earnings.

e) *YMPE*

Year's Maximum Pensionable Earnings, as defined under the Canada Pension Plan.

Member Contributions

Members are required to contribute, in each year, an amount equal to 3.5% of Earnings up to the YMPE, plus 5.0% of Earnings, if any, in excess of the YMPE.

Normal Retirement

a) *Date*

First day of the month following attainment of age 65 ("Normal Retirement Date").

b) *Annual Pension*

Accrued Pension at the Normal Retirement Date.

Early Retirement

a) *Date*

First day of any month following attainment of age 55 or completion of 30 years of Credited Service ("Early Retirement Date").

b) *Annual Pension*

Accrued Pension at the Early Retirement Date reduced by:

(i) 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 62; plus

(ii) 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 60.

No reduction applies if age plus Credited Service totals at least 90 years.

c) *Supplemental Benefit*

1/35 of $400 for each year of Credited Service (maximum 35) payable from the Early Retirement Date to the Normal Retirement Date.

Postponed Retirement

a) *Date*

First day of any month after the Normal Retirement Date but not later than December 1st of the calendar year the member attains age 71 ("Postponed Retirement Date").

b) *Annual Pension*

Accrued Pension at the Postponed Retirement Date.

Termination of Employment

Accrued Pension payable at the Normal Retirement Date. Members may elect to receive a pension at any time after the Early Retirement Date on an actuarial equivalent basis.

Pre-Retirement Death Benefits

a) *Benefit*

The lump sum which is the actuarial equivalent of the Accrued Pension accrued to the date of death.

b) *Additional Benefit*

Refund of required member contributions with interest which are in excess of 50% of the value of benefits accrued under the plan.

Form of Pension

The normal form of pension payment provides for a refund of required member contributions with interest in excess of the aggregate pension payments received by the member. Members may elect a different form of payment on an actuarial equivalent basis.

Disability Benefits

Upon total and permanent disability prior to Normal Retirement Date, required member contributions cease and Applicable Credited Service continues to accrue until the earlier of the return to employment and age 65.

Group Three Plan

The provisions of the Group Three Plan are identical to the provisions of the Group One Plan except that the Benefit Accrual Rate under the Flat Dollar Provision is $45.25 multiplied by 12.

Post Retirement Benefits Other than Pensions

Westcoast PRBs

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Union Gas PRBs

Eligibility Age 55 and retire prior to January 1, 2006 and do not choose the Common Plan

Life Insurance

■ Management & Supervisory Employees	2 x annual pre-retirement earnings; amount reduces by 25% of original amount each year to a minimum of $5,000.
■ All other employees	$2,500

Extended Health Benefits

■ Annual deductible	$10 single, $20 family
■ Overall maximum	$10,000 per person per year (under age 65); $10,000 per person lifetime (age 65 and over)
■ Prescription drugs	100%
■ Hospital rooms	100% semi-private
■ Ambulance	100%
■ Home nursing care	100%, maximum 400 hours lifetime
■ Accidental dental	100%
■ Psychologist, speech therapist	100%, maximum $200 per year
■ Physiotherapist	100%, no maximum
■ Massage therapist	100%, maximum $7 per treatment for 12 treatments
■ Other medical items	100% of eligible expenses
■ Out of country	100%, maximum $10,000 lifetime
■ Hearing aids	None
■ Vision care	None
■ Survivor benefit	■ for spouses under age 65, until the end of the month in which the spouse attains age 65; or ■ for spouses age 65 and over, for a maximum of 3 months

Dental Care Benefits

■ Coverage	To age 65 only
■ Basic	100%
■ Major restorative	50%, maximum $5,000 lifetime per person
■ Orthodontia	50%, maximum $1,000 lifetime per person
■ Survivor benefit	Coverage continues to eligible dependents for 3 months upon the death of retiree

Retiree Supplemental Health Services Plan

■ Annual allowance	Management and Supervisory Employees: $75 single, $150 family Other Employees: $50 single, $100 family
■ Survivor benefit	■ for spouses under age 65, until the end of the month in which the spouse attains age 65; or ■ for spouses age 65 and over, for a maximum of 3 months

Centra Salaried PRBs

Eligibility	Age 55 and retire prior to January 1, 2006 and choose not to participate in the Common Plan
Life Insurance	3 x annual pre-retirement earnings rounded to the next higher $1,000; reduced by 20% at earlier of age 66 or 1st anniversary of retirement; and reduced by 20% of original amount each year to a minimum of $2,500
Extended Health Benefits	
■ Annual deductible	$25 single, $50 family
■ Overall maximum	Unlimited
■ Prescription drugs	100%
■ Hospital rooms	100% semi-private or private
■ Ambulance	100%
■ Home nursing care	100%, maximum $5,000 per year
■ Accidental dental	100%
■ Psychologist, chiropractor, speech therapist, naturopath, massage therapist, dietician, chiropodist and osteopath	100%, maximum $350 per year for each paramedical practitioner
■ Physiotherapist	100%, maximum $400 per year
■ Athletic therapist	100%, maximum $100 per year
■ Other medical items	100% of eligible expenses
■ Out of country	100% of eligible expenses
■ Hearing aids	Maximum $300 every 5 years
■ Vision care	None
■ Survivor benefit	Coverage continues to eligible dependents upon the death of retiree to age 65
Dental Care Benefits	No coverage

USW & CEP North PRBs

Eligibility	Age 55 and retire prior to January 1, 2006 and choose not to participate in the Common Plan
Life Insurance	
■ USW Employees	$40,000 at retirement; reduced by 25% of original amount each year to a minimum of $1,500
■ CEP North Employees	$55,000 at retirement; reduced by 25% of original amount each year to a minimum of $1,500
Extended Health Benefits	
■ Coverage	To age 65 only
■ Annual deductible	USW Plan - $0.35 per prescription for prescription drugs only CEP North Plan – None
■ Overall maximum	USW Employees: Unlimited CEP North Employees: $25,000 lifetime maximum per person, excluding drugs
■ Prescription drugs	100%
■ Hospital rooms	100% semi-private
■ Survivor benefit	Coverage continues to eligible dependents upon the death of retiree to age 65
Dental Care Benefits	No coverage

Common PRBs

Eligibility

■ Retire prior to 2006	Age 55 and choose to participate in the Common Plan
■ Retire after 2005	
— Full benefits	Age 55 with 15 years of service; or Age plus service after age 55 greater than 70 points
— Life insurance, extended health benefits and provincial health care premium; no health care spending account	Age 55
— Life insurance, extended health benefits provincial health care premium and reduced health care spending account amount	Age 55 with number of years of service between 1 to 14 at retirement

Life Insurance $10,000

Extended Health Benefits

■ Annual deductible	$1,200 per person
■ Overall maximum	$500,000 per person lifetime
■ Prescription drugs	100%
■ Hospital rooms	None
■ Ambulance	100%
■ Home nursing care	100%, maximum $10,000 per year
■ Accidental dental	None
■ Psychologist, speech therapist, physiotherapist, chiropractor, massage therapist, naturopath, chiropodist, podiatrist, homeopath and social worker	100%, combined maximum $500 per year for all practitioners
■ Other medical items	100% of eligible expenses
■ Out of country	None
■ Hearing aids	Maximum $500 every 5 years
■ Vision care	None
■ Survivor benefit	■ for spouses under age 65, until the end of the month in which the spouse attains age 65; or ■ for spouses age 65 and over, for a maximum of 3 months

Dental Care Benefits No coverage

Health Care Spending Account

- Annual allowance
  - Full amount: Under age 65 - $1,500 per retiree (whether single or family)
    Age 65 and over - $1,200 per retiree (whether single or family)
  - Reduced amount: Full amounts as stated above reduced based on the following table

Service at retirement	Reduction
0	100%
1	93.3333%
2	86.6667%
3	80.0000%
4	73.3333%
5	66.6667%
6	60.0000%
7	53.3333%
8	46.6667%
9	40.0000%
10	33.3333%
11	26.6667%
12	20.0000%
13	13.3333%
14	6.6667%
15	0%

- Survivor benefit
  - for spouses under age 65, until the end of the month in which the spouse attains age 65; or
  - for spouses age 65 and over, for a maximum of 3 months

Provincial Health Care Premiums

- Benefit: Payment of full amount of provincial health care premiums
- Survivor benefit: Coverage continues to eligible dependents upon the death of retiree

Employer Representation

With respect to the information summarized or referenced in this report, I hereby confirm that to the best of my knowledge and belief:

- As per applicable accounting standards, the assumptions set forth for each plan in the report reflect Spectra Energy Transmission's best estimates regarding future events as at December 31, 2011. The discount rate was selected by Spectra Energy Transmission, based on market bond yields as at December 31, 2011;
- the description of the methods and the accounting policies employed, included in the report, is complete and accurate, and is in accordance with Spectra Energy Transmission's accounting policies;
- the membership data summarized in the report are a complete and accurate description of all employees or former employees who are or may become entitled to benefits under the terms of the plans;
- the information on plan assets forwarded to Towers Watson and summarized in the present report is complete and accurate;
- the plan provisions, as described in this report, are a complete and accurate description of all pension and post-retirement benefits to which employees and former employees may become entitled and which have a material effect on the determination of the obligations and costs associated with Spectra Energy Transmission's post-retirement benefits; and
- there have been no events subsequent to the valuation date that would materially change the financial position or costs of the plans as at the valuation date.

____
Signature

____
Name

____
Title

____
Date

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.2

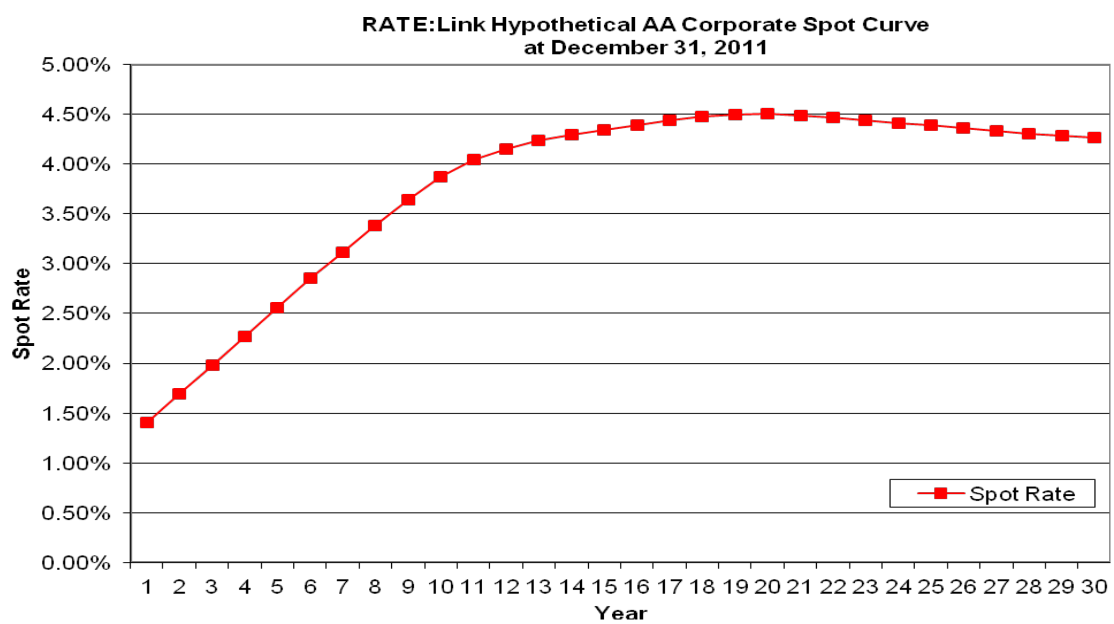
Union updated its assumption of the discount rates for defined benefits pension costs to 4.3% and post-retirement benefits to 4.33% based on a hypothetical AA Corporate yield curve for long terms bonds.

a) Please provide the hypothetical AA Corporate yield curve to show that the 4.3% and 4.33% discounted rates used are supported by the yield curve of the long term bonds.

b) Please also demonstrate that the long term bonds selected by Union covering a time period horizon approximate the period of Union's future benefit payments for its defined benefit pension plans and post-retirement benefit plans.

Response:

a) The hypothetical yield curve is shown below:



b) The durations of the liabilities for pension and post-retirement benefits used to determine the discount rates as at December 31, 2011 from the yield curve in a) above were 13.9 years and 15.2 years, respectively.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.3

Union updated its assumption related to expected return on plan assets from 7% in 2011 to 6.75% in 2012 and 6.50% in 2013. Union stated that the reduction is to reflect the low returns being experienced in the marketplace in addition to broad industry benchmarking information.

a) Please explain further how the expected returns on plan assets are determined.

b) Please provide Union's internal analysis of these two figures.

c) Please provide the broad industry benchmarking information referred above.

Response:

a) The expected rate of return on plan assets is Union's best estimate of the expected long-term rate of return to be earned on the pension plans' assets, determined in accordance with US GAAP. The expected rate of return takes into account the allocation of assets between investment classes and the investment policy for the plans. In determining the expected rate of return Union relies upon various capital market forecasts including Towers Watson's Capital Markets Model.

b) Using Towers Watson's Capital Markets Model and the target investment allocations based on the investment policy of the plans, a range for the expected rate of return on assets for 2012 was determined as 6.0% to 6.9%. Based on this analysis and taking into account other data sources, Union selected a rate of return for 2012 of 6.75%. The expected rate of return on assets for 2013 of 6.50% has been estimated taking into account the 2012 expected rate of return and expected trends in the rate based on various economic and related data sources.

c) Towers Watson conducts an annual survey of accounting assumptions. The most recent survey was conducted in January and February 2012. The results for the expected rate of return on assets are shown below:

	Expected Return on Assets Used for Fiscal Year Ending	
	2011	Estimated 2012
Number of responses	155	152
25th percentile	6.25%	6.00%
Median	6.75%	6.50%
75th percentile	7.00%	7.00%
Mean	6.67%	6.43%

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit D1, Tab 3, page 10

Union provided in Table 4 a comparison of employee future benefit costs, which comprise of defined benefits pension costs, post-retirement benefits costs, and defined contribution pension costs, for the years of 2007, 2011, 2012 and 2013. Union indicated that the expenses for defined benefit pension and post-retirement benefits for 2012 and 2013 are determined in accordance with USGAAP while the expenses are determined in accordance with CGAAP for years 2007 through 2011. Please reproduce the table to include the years 2007 to 2013 for defined benefit pension costs as shown below:

Defined benefits Pension	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	CGAAP					USGAAP	
1) Current service Cost							
2) Interest Cost							
3) Benefits Paid							
4) Expected return on assets							
5) Amortization of Past service Cost							
5) Amortization of Actuarial gains/losses							
6) Amortization of Transitional Obligation						Not applicable under US GAAP	
Total	**$21.5**				**$35.4**	**$36.2**	**$34.2**

Note: please include other lines in the table as needed.

Please ensure that the total defined benefit pension costs in each year agree to the defined benefit pension costs in relevant years' AFSs.

Response:

Defined Benefit Pension	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	CGAAP					**USGAAP**	
1) Current service cost	$10.7	$10.4	$9.5	$11.0	$12.3	$15.8	$16.7
2) Interest cost	27.3	29.5	31.2	32.9	32.6	31.8	33.5
3) Benefits paid							
4) Expected return on assets	(31.2)	(34.6)	(33.6)	(33.9)	(34.2)	(40.5)	(43.4)
5) Amortization of actuarial (gains)/losses	11.7	6.5	6.8	14.5	21.2	26.0	25.6
6) Amortization of transitional obligation	1.8	1.8	1.7	1.5	1.5	Not applicable under US GAAP	
7) Amortization of past service costs	0.9	0.9	0.9	1.5	1.6	1.5	1.5
8) DB filing fees	0.3	0.3	0.3	0.4	0.4	0.3	0.3
9) Amortization of regulatory asset(2)						1.3 (1)	
Total	**$21.5**	**$14.8**	**$16.8**	**$27.9**	**$35.4**	**$36.2**	**$34.2**

(1) Union's 2012 rates are based on CGAAP therefore, the 2012 DB pension expense includes the write off of the 2012 allocation of the transitional obligation and the 2012 impact of the change in measurement date.

(2) Union will address the disposition of the remaining balance at December 31, 2012 of deferral account 179-127 *Pension Charge on Transition to US GAAP* in the 2012 annual deferral disposition proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.10

Union has indicated in its application that the change to U.S. GAAP results in a decrease in net pension cost of $2.8 million.

a) Please provide in which year this decrease has occurred.

b) Please provide the calculations for the $2.8 million.

Response:

a) Union transitioned to USGAAP effective January 1, 2012, however, the 2012 forecast for Employee Benefits includes an amortization of the regulatory asset equal to the impact on 2012 of the transition to USGAAP. Therefore, the year in which a decrease to Employee Benefits is first noticed is 2013.

b) The $2.8 million represents the elimination of the amortization of the transitional obligation from the defined benefit pension and post-retirement benefits expense for 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.10; Exh D1/Tab 3/Schedule 1

Union provided a reconciliation of pension costs from 2011 Canadian GAAP to 2013 USGAAP in schedule 1 of Exhibit D1 Tab 3. As per the reconciliation schedule line 2 and line 3, the decrease in net pension expenses in 2011 under USGAAP as compared to CGAAP is $3.9 million, which is comprised of the $3.3 million for transitional obligation and 0.6 million for change in measurement date.

Please reconcile the $3.9 million with the $2.8 million referred on page 10 of Exhibit D1 Tab 3.

Response:

The $3.9 million is the difference between CGAAP and USGAAP expense in 2011. The $2.8 million represents the amortization of the transitional obligation for 2013. The table below reconciles the changes in defined benefit pension and post-retirement benefits expense for 2011 to 2013:

	($millions)		
	2011	2012	2013
Amortization of transitional obligation	$3.3	$2.7	$2.8
Impact of change in measurement date	0.6	(0.1)	TBD (1)
Total difference between CGAAP and USGAAP	$3.9	$2.6	TBD

(1) The impact of the change in measurement date for 2013 cannot be determined until the finalization of the plan experience in the fourth quarter of 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 3/ Pg.12

Union has indicated that the post-retirement benefit costs for 2013 are forecast to be approximately $7.6 million, a decrease of $0.7 million from the amount included in rates approved in 2007. The decrease in DB costs is primarily as a result of the change in accounting to USGAAP.

Please confirm that the change in accounting to USGAAP is related to unamortized transitional obligation to be recorded in the USGAAP deferral account which was approved by the Board in EB-2011-0025. Please provide the amount related to the post-retirement benefits to be recorded in the deferral account and proposed by Union for recovery in 2013.

Response:

Union confirms the change in accounting to USGAAP is related to the unamortized transitional obligation and the cumulative change in the measurement date to be recorded in the USGAAP deferral account. The balance in the deferral account at December 31, 2012 is expected to be:

Defined Benefit Pension	$3.3 million
Other post-retirement benefits	$4.5 million
Total	$7.8 million

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, page 12, Original & Updated

In the original version of Exhibit D1, Tab 2, at page 12 it was noted that there was a reduction of $10.6 million related to USGAAP for pension costs between 2012 and 2013. In the updated evidence, the Benefits variance is now a reduction of $1.1 million between 2012 and 2013 and there is no mention of a decrease in costs related to the conversion to USGAAP. Please provide a table that shows now the net reduction of $1.1 million between 2012 and 2013 has been derived, including the impact of moving from CGAAP to USGAAP on pension costs.

Response:

The reduction of $10.6 million is not entirely due to the conversion to USGAAP. The reduction is equal to the previous expected reduction between 2012 and 2013 in addition to the conversion to USGAAP.

A reconciliation of the $1.1 million between 2012 and 2013 is as follows:

	($ millions)
2012 USGAAP	82.2
Reduced by:	
Amortization of regulatory asset from 2012	(2.6)
Expected experience in defined benefit pension and other post-retirement benefits	(0.3)
Increased by:	
Increase in defined contribution pension	0.3
Increase in employee benefits	1.5
2013 USGAAP	81.1

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, Addendum &Exhibit D1, Tab 3, Table 4, Original & Updated

a) The total cost of employee future benefits has increased by $19.4 million, as shown in Table 4 of the updated evidence as compared to the original evidence. Please provide a breakdown of this increase into the three components noted in the Addendum: changes in the expected return on plan assets, changes to the discount rate and changes to the mortality assumption.

b) Is Union proposing to update the expected return on plan assets and/or the discount rate to reflect actual data at the same time that the Board calculates the return on equity to be used for January 1, 2013 rates, which is likely to be based on September, 2012 data. If not, please explain why not.

Response:

a) Please see the response at Exhibit J.D-1-2-5 i).

b) Union is not proposing to update the expected return on assets and/or the discount rate for January 1, 2013 rates. The expected return on assets reflects management's best estimate of the expected long-term return of the plan assets and the actual discount rate will not be known until shortly after the December 31, 2012 year end.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3 &
Exhibit D1, Tab 3, Table 4,

a) Please provide a breakdown of the drivers for the $19.4 million increase in future benefits.

b) Please provide an update of the expected return on plan assets.

Response:

a) Please see the response at Exhibit J.D-1-2-5 i).

b) Please see the response at Exhibit J.D-8-2-2 b).

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit D1, Tab 3, page 15

Union has proposed to source payroll/Human Resource Management System ("HRMS") through a Service Level Agreement with Spectra Energy utilizing SAP on a go-forward basis. SAP will be implemented across Spectra Energy business units. The cost of implementation will be shared amongst the other business units within the broader company.

a) Please indicate the basis on which costs will be split amongst the different business units within Spectra. Please provide a detailed response.

b) Please provide a copy of the Service Level Agreement between Union and Spectra Energy for providing payroll and HRMS services.

Response:

a) The capital cost for Spectra to implement HRMS and payroll functionality is estimated to be $22.2 million. These costs will be amortized over 10 years and allocated to each business unit (BU) based on headcount. Union has approximately 41% of Spectra's total head count. Union's annual cost is estimated to be $0.915 million.

   The general and administrative costs related to Union's payroll department are expected to be unchanged as a result of the new software and will continue to be allocated using a fully allocated cost approach across Spectra based on headcount.

b) The Service Level Agreements (SLA) for 2013 HR services are not currently available. These agreements will be finalized in Q1 2013.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, page 4, Updated

a) What is the impact on the human resources related costs in the 2013 test year if the salary increases contained in the 2012 and 2013 forecast were 2.0% in each year?

b) Please provide the corresponding percentage salary increases for each year of 2007 through 2011.

c) What is the impact on the human resources related costs in the 2013 teat year if the salary increases for 2012 is set at 2.5% with a freeze on wages and salaries for 2013?

Response:

a) The impact on the human resource related costs in the 2013 test year if the salary increases contained in the 2012 and 2013 forecast were 2% in each year is a reduction to net utility O&M costs of $4.1 million. Union notes that 2012 salary increases are already in place and much of the 2013 increases are fixed through collective bargaining agreements.

b) The corresponding percentage salary increases for each year from 2007 to 2011 is shown in the table below:

2007	2008	2009	2010	2011
3.4%	3.6%	2.4%	3.0%	3.0%

c) The impact on the human resource related costs in the 2013 test year if the salary increase for 2012 is set at 2.5% with a freeze on wages and salaries for 2013 is a reduction to net utility O&M costs of $6.5 million. As stated in a) above, 2012 salary increases are already in place, and much of the 2013 increases are fixed through collective bargaining agreements.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, Updated

a) Please provide a table for 2007 through 2011 actual and forecasts for 2012 and 2013 that shows the total variable pay paid (or forecast to be paid), the total variable pay available (assuming 100% payout to all employees) and the corresponding ratio of the actual variable pay to the potential variable pay.

b) Please provide a table the splits the variable pay (both actual and potential) between STIP and LTIP for each of 2007 through 2011 actual and the forecasts for 2012 and 2013.

c) How does Union determine or allocate variable pay between the regulated and unregulated components of its business?

d) Please provide the variable pay related to the unregulated business in each of 2007 through 2011 actual and the forecasts for 2012 and 2013 and please confirm that these figures are not included in the figures shown in Table 1.

e) With respect to the pension choices noted on page 7, please provide the number of employees that selected the Defined Benefit plan and the number that selected the Defined Contribution plan for each of the last three years of historical data and the forecast for the 2012 and 2013 years that underpins Union's cost forecasts for these programs. Please also provide the current number of employees in each plan.

Response:

a) Please see Attachment 1.

b) Please see Attachment 1.

c) Variable pay is allocated between regulated and unregulated components of the business based on the percentage of the most current year actual unregulated O&M costs as a percentage of total net O&M costs.

d) The variable pay for the unregulated business is included in the table below. The variable pay for the unregulated business is included in Table 1.

Year	Variable Pay ($000's)	Allocator	Unregulated ($000's)
2007	14,528	2.0%	291
2008	18,578	2.0%	372
2009	16,252	2.9%	471
2010	22,770	3.0%	683
2011	25,210	3.0%	756
2012	18,328	3.0%	550
2013	19,030	3.0%	571

e) As of April 2012 there were 1,348 employees in the Defined Benefit plans. 119 employees enrolled in the Defined Benefit plans in 2011, 81 in 2010, and 49 in 2009. The forecast for the 2012 and 2013 Defined Benefit plans is based on membership data as at December 31, 2010. The forecast assumes that the number of active members and the age/service distribution of the active members remains constant through the projection period. No explicit provision is made for new entrants.

As of April 2012 there were 942 employees in the Pension Choices Defined Contribution plan. 26 employees enrolled in the Defined Contribution plan in 2011, 17 in 2010, and 26 in 2009. The forecast for 2012 and 2013 assumes no net change to the Defined Choices plan membership. It is estimated that the number new entrants will approximate the number of members who exit the plan.

UNION GAS LIMITED

Variable Pay Details for 2007-2013

	2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
Total Variable Pay Paid/Forecast ($)	14,528,208	18,578,407	16,251,965	22,770,151	25,210,154	18,327,607	19,030,474
Total Variable Pay Available (100% Payout) ($)	13,273,271	13,695,523	14,843,922	16,771,067	17,717,261	18,327,607	19,030,474
Ratio of Total Variable Pay Paid/Forecast to Total Variable Pay Available ($)	109%	136%	109%	136%	142%	100%	100%

Variable Pay Break-down STIP/LTIP (2007-2013)

	2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
STIP ($)	12,527,976	16,577,904	14,557,259	20,390,246	22,691,795	15,230,866	15,758,465
LTIP ($)	2,000,232	2,000,503	1,694,707	2,379,905	2,518,359	3,096,741	3,272,009
Total Variable Pay Paid/Forecast ($)	14,528,208	18,578,407	16,251,965	22,770,151	25,210,154	18,327,607	19,030,474
STIP ($)	11,851,205	12,260,946	12,530,922	13,988,475	14,583,844	15,230,866	15,758,465
LTIP ($)	1,422,066	1,434,577	2,313,000	2,782,592	3,133,417	3,096,741	3,272,009
Total Variable Pay Available (100% Payout) ($)	13,273,271	13,695,523	14,843,922	16,771,067	17,717,261	18,327,607	19,030,474

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, pages 15-16, Updated

a) Has Union done any surveys or interviews with the employees that are eligible to retire within the next five years to see if the employees intend to retire as soon as they are eligible? If not, why not? If yes, please provide a summary of the results.

b) Eligibility for Old Age Security has been pushed back from age 65 to 67 with a phase in over a number of years that impacts employees that are currently less than 54 years of age the most. Based on the average age of employees in the defined contribution pension plan shown in Table 5 of 45.6 years, what impact does Union believe this will have on the retirement timing of its employees?

Response:

a) Union has not conducted a comprehensive survey, but rather focuses its inquiries for this type of information from employees in Front Line Technical roles, currently eligible to retire. The front line technical roles represent our most significant workforce challenge. This information is used to refine our retirement forecast for Utility Service Representatives (USRs) in the development of our annual Utility Service Representative hiring plans. The information is used to confirm the specific retirements are known in rural, remote and urban locations. Union Gas then ensures sufficient qualified employees are available in districts throughout the franchise area or may contract out work to establish a viable work plan.

b) Union has not reviewed the specific impact of the changes to Old Age Security on the retirement intentions of its employees. Employee retirement decisions are based on a variety of economic and demographic factors, including the availability of government pensions. Furthermore, an employee's commencement of receipt of government benefits may not always be coincident with retirement from employment with Union. Therefore, any forecasts of the specific impact of these changes on Union's workforce would include a significant degree of uncertainty.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, Appendix A

a) The Towers Watson report was based on using 2010 as the base year. Is information now available to use 2011 as a base year? If so, please update the report using 2011 as the base year.

b) Please update the evidence at pages 3 and 4 to reflect the most recent information available from the sources quoted.

c) What is the impact on the 2013 revenue requirement if the 2011 average actual salary increases shown in Appendix I for each of the four employee groups were used for both 2012 and 2013?

Response:

a) Yes. Please see Attachment 1.

b) Please see Attachment 1.

c) Union does not track costs in the categories shown in Appendix 1 of the Towers Watson report and has therefore combined the Managers / Salaried Professionals categories and used the average increase of these two categories (3.0%). The impact to net utility O&M is $0.7 million. If O&M is increasing by $0.7 million, then the revenue requirement will also increase by $0.7 million.

TOWERS WATSON

175 Bloor Street East
South Tower, Suite 1701
Toronto, Ontario M4W 3T6
Canada

T +1 416 960 2700

towerswatson.com

Private and Confidential

April 24, 2012

Mr. Chuck E. Conlon
Director, Employee and Labour Relations, East
and Business Services
Spectra Energy Transmission
50 Keil Drive North
Chatham, ON
N7M 5M1

Dear Chuck:

UNION GAS 2013 RATE APPLICATION – TOTAL CASH COMPENSATION

This letter has been prepared for Union Gas Limited (the "Company") in support of its 2013 rate application, and provides information on:

- The Company's changes in base salary from 2007 - 2012, with an outlook for 2013; and
- Eligibility for participation in the Company's short-term incentive plan and the level of short-term incentive targets.

Total cash compensation for regular full-time employees consists of base salary and short-term incentive compensation. The purpose of the short-term incentive is to provide employees with an element of pay at risk, as it is paid only in recognition of success against assigned corporate, business unit and individual / team objectives. Performance measures and associated weights are reviewed and revised annually to align with current business objectives. For each measure, a minimum performance threshold is established; if actual performance is below the threshold, no payout for that element will occur.

The inclusion of a short-term incentive within the structure of the Company's total cash compensation, and the performance measures associated with the short-term incentive plan are consistent with competitive market practice among Utility and Power Services companies, including those used in our analysis.

BASE PAY TRENDS

Methodology

In 2007, the Company's costs were reviewed when rates were approved by the Ontario Energy Board. While 2011 will be used as the base year to compare the trend in compensation costs between Union Gas Limited and the competitive labour market, for historical context we have provided a summary of average actual (and projected) salary increases for both Union Gas and companies in the Utility and Power Services sector (2007 – 2012). A summary of this data can be found in Appendices I & II.

Base salary is the foundation upon which total compensation is typically based in the marketplace. For this analysis and commentary, the Company's workforce is divided into four groups – Executive, Management, Salaried Professional, and Unionized. This letter focuses on trends in base pay from 2011 - 2012 using data from a custom sample of companies ("Comparator Group") participating in Towers Watson's 2011/2012 Salary Budget Survey with revenues between $1B -$5B (approximately half-to-double the revenue of Union Gas). The trend in base salary movement since 2011 will provide a reasonable indication of the degree to which the Company's total cash compensation (salary + incentives) has kept pace with the competitive market.

Most organizations do not project salary increase budgets beyond one year. Consequently, our estimate of salary projections for 2013 is based on the current environment (i.e., 2011 actual increases and 2012 projections), our reviews of economic forecasts, and historical trends in salary increases.

Current and Projected Salary Increases

When setting base salary budgets, Union Gas considers salary increase forecasts reported by external compensation consultants (such as Towers Watson), consumer price index projections, and negotiated wage settlements with unionized labour. Base salary increases for non-union employees are then administered against established guidelines that consider an employee's individual performance, demonstrated growth and development. As a result, in some cases actual increases may fall below budget.

Over the period covered by our analysis, overall Union Gas' salary budgets have aligned with the competitive market. While average actual salary increases may vary slightly (above or below) market for a particular employee level, in aggregate increases have been consistent with market trends.

Executives

For 2011, the actual median increase for executive base salaries within the Comparator Group was 3.0%, as compared to the Company's 2011 average actual salary increase of 2.90%. The projected 2012 salary increase for executives is 3.2% in the Comparator Group, resulting in a cumulative market increase of 6.2% from 2011 to 2012. By comparison, the Company's 2012 average salary increase for executives is 2.35%, resulting in a cumulative increase of 5.25% over the same period.

Managers

For 2011, the actual median increase for management base salaries within the Comparator Group was 3.0%, as compared to the Company's 2011 average actual salary increase of 3.15%. The projected 2012 salary increase for managers is 3.0% in the Comparator Group, resulting in a cumulative market increase of 6.0% from 2011 to 2012. By comparison, the Company's 2012 average salary increase for managers is 3.06%, resulting in a cumulative increase of 6.21% over the same period.

Salaried Professionals

For 2011, the actual median increase for salaried professional base salaries within the Comparator Group was 3.0%, as compared to the Company's 2011 average actual salary increase of 2.85%. The projected 2012 salary increase for salaried professionals is 3.0% in the Comparator Group, resulting in a cumulative market increase of 6.0% from 2011 to 2012. By comparison, the Company's 2012 average salary increase for salaried professionals is 2.94%, resulting in a cumulative increase of 5.79% over the same period.

Unionized Employees

For 2011, the average wage rates for the Company's unionized employees increased by a total of 3.0%. This average adjustment is consistent with marketplace movement during this period for Salaried Professionals. The Company's 2012 wage rate increase for unionized employees is 3.0%.

Forecast Beyond 2012

In February 2011, Towers Watson provided a memo to Spectra Energy (dated February 17, 2011) regarding salary escalation factors for non-union employees for the 2011 – 2013 time frame. The February memo was updated in October 2011 (dated October 26, 2011), but provided no new recommendations for projected salary increases. At that time, taking into account historical salary increases, and economic forecasts for the Utility and Power Services and Oil and Gas industries, Towers Watson recommended a preliminary salary projection range of 3.0% - 4.0% for 2012 and 2013. Our salary recommendation for 2013 remains in the range of 3.0% - 4.0%.

For this analysis, we have provided updated economic forecasts produced by the Bank of Canada and major Canadian Banks. The most recent report from these sources indicates that the expected pace of growth for the Canadian economy is modest but more positive than previously forecast given ongoing global economic uncertainty. Notwithstanding this expectation, the updated forecasts continue to support our recommendation for 2013:

<u>Observations and Predictions for Canada:</u>

- The Bank of Canada estimates that the *"economy will grow by 2.4 per cent in both 2012 and 2013 before moderating to 2.2 per cent in 2014… the economy is expected to return to full capacity in the first half of 2013".* (Bank of Canada Monetary Policy Report April 2012).
  - The Bank expects core inflation to stay close to 2 per cent through their projection period. The Bank further notes that total CPI inflation is *"projected to decline in the near term to close to 2 per cent, in part reflecting lower core inflation, and to remain around the target over the balance of the projection horizon. The Bank no longer expects total CPI inflation to move significantly below 2 per cent later in 2012."*

- Bank of Montreal's April 4, 2012 report indicates that Canada's *"growth should slow to 2.0% this year from 2.5% in 2011, before returning to the latter pace in 2013 on firmer U.S. demand."* (North American Outlook report, April 4th, 2012).

- Toronto Dominion Bank's March 19, 2012 forecast states that the *"real GDP growth is projected to run at 2.2% in 2012… the catalyst behind this positive adjustment is an improvement in the near-term environment for the global economy and financial markets…"* TD Bank forecasts growth of 2.4% in fiscal 2013. (Quarterly Economic Forecast, March 19th, 2012).

<u>Provincial Economic Forecasts</u>

Economic analysts believe that Ontario's recovery will be bolstered by a rebound in the manufacturing sector, but the Province will continue to face modest growth as a result of the Ontario government's budget cuts to eliminate the deficit.

- Toronto Dominion Bank's Provincial Economic Forecast cites the recovery in manufacturing as a positive step for Ontario; however, overall growth is tempered by a high exchange rate, the ratcheting down of growth in housing and financial services, and the government's plan to cut spending in real terms. Consequently, TD Bank forecasts Ontario's growth at 2.1% in 2012, and 2.3% in 2013. (TD, Provincial Economic Forecast, April 9, 2012).

- RBC's projections for Ontario are similar: *"While we expect growth in the province to accelerate modestly in 2012 from 2011, economic performance in Ontario will continue to face stiff headwinds from the high value of the Canadian dollar… [and] from the ramping up of government program spending restraints… We expect such headwinds to slow growth to 2.3% in 2013."* (RBC, Provincial Outlook, March 2012).

INCENTIVE PROGRAM

Methodology

We have compared short-term incentive eligibility and average short-term incentive targets (expressed as a percentage of salary) for three of the four employee groups (Executive, Management, and Salaried Professionals). Comparisons have been made against a National comparator group, defined as companies participating in Towers Watson's 2011 Compensation Data Bank with revenues between $1B - $5B.

Executives

Within the National comparator group, close to 100% of executives in comparable salary bands are eligible to participate in short-term incentive plans. Based on 2011 data, the average incentive target for the Company's executives is 34%, which is slightly below the market median target of 40% for the National comparator group.

Managers

Within the National comparator group, approximately 80% of managers in comparable salary bands are eligible to participate in short-term incentive plans. Based on 2011 data, the average incentive target for the Company's managers is 14%, and is aligned with the market median target of 15% for the National comparator group.

Salaried Professionals

Within the National comparator group, approximately 80% of salaried professionals in comparable salary bands are eligible to participate in short-term incentive plans. Based on 2011 data, the average incentive target for the Company's salaried professionals is 8%, compared with a range of 8% to 10% at market median for the National comparator group.

OPINION

Base Pay

Based on available forecasts the recovery of the Canadian economy has been stronger than expected, but will continue to be restrained given global market conditions. While it is anticipated that the Canadian labour market will continue to improve, job growth is occurring most prominently in Alberta (as a result of high oil prices), and Saskatchewan. The overall national unemployment rate is expected to decline in 2012 and 2013.

We note that Union Gas' average actual salary increases trailed other Utility and Power Services companies in Canada between 2007 – 2009. Though Union Gas' increases were slightly higher in 2010, this is not unexpected in light of their lower positioning in the prior years. Union Gas' 2011 increases were consistent with actual market median increases in the Utility and Power Services sector; however, Union Gas' 2012 increases are below market projections in this sector. In relation to the Comparator

Group, on an aggregate basis Union Gas' salary increases for 2011 and 2012 remain competitively positioned.

Recent and projected market movements in base salary exceed adjustments made by Union Gas to Executive and Salaried Professional employees over the comparable period. At the same time, salary increases for the Company's Management and Union employees have mirrored the market. Since our last market letter dated October 26, 2011, we note that the base salary adjustments determined by Union Gas more closely align the Company with its market comparators and with economic trends.

Incentives

Short-term incentives are a common component of total cash compensation among comparable market organizations. In our opinion, the existence of Union Gas' short-term incentive plan and the target incentive levels for all participating employees are consistent with market practice. Their plan is essential to ensure the Company continues to attract, motivate and retain talent, which in turn will enhance Union Gas' ability to effectively serve customers in a competitive market environment.

In summary, based on our analysis, it is our opinion that over the period covered in our analysis, Union Gas' salary increases and target incentive levels are appropriately aligned with competitive market practice.

* * * * *

We trust that this letter provides you with the information you require at this time. Please contact me if you have any questions you wish to discuss.

Sincerely,

Elizabeth Greville
Director
416-960-2754

cc: Ashley Witts – Towers Watson / Vancouver

Appendix I – Union Gas Average Actual Salary Increases

Employee Group	Average Actual Salary Increases					
	2007	2008	2009	2010	2011	2012
Executives	3.21%	4.75%	2.50%	3.75%	2.90%	2.35%
Managers	3.59%	3.88%	2.46%	3.11%	3.15%	3.06%
Salaried Professionals	3.31%	3.51%	2.42%	2.89%	2.85%	2.94%
Unionized	2.88%	2.97%	2.50%	3.00%	3.00%	3.00%

Appendix II – Actual and Projected Salary Increases in Utility & Power Services Industry

Employee Group	Median Actual Salary Increases [1]					
	2007	2008	2009	2010	2011	2012E
Utility & Power Services						
Executives	5.8%	5.8%	3.0%	2.5%	3.0%	3.3%
Managers	5.5%	5.4%	3.5%	2.6%	3.0%	3.5%
Salaried Professionals [2]	4.2%	4.3%	3.6%	2.6%	3.0%	3.3%

[1] Includes employees w ho do not receive an increase

[2] As of 2007, Salaried professionals w ere defined as Production and Technical/Administrative Support employees

Note:

2007-2009 data from Tow ers Perrin Salary Management Surveys

2010 data from TW 2010/2011 Salary Budget Survey Report (Utilities & Energy)

2011 actual and 2012 projections from TW 2011-12 Energy Sector Salary Management Report (Updated January 2012)

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 3, Appendix B

a) Has Union made any changes to the STIP plan for 2012? If yes, please describe the changes made.

b) Please provide a breakdown of the total STIP payment made for 2011 and the forecasts for 2012 and 2013 into the dollar amount associated with each of the measures shown in the table at the top of page 4. If this breakdown is not possible, please provide an estimate of the 2013 STIP payment broken down based on each of the measures.

c) For each of the measures shown in the table at the top of page 4, please explain the benefits to ratepayers of the regulated portion of Union Gas of achieving the targets.

d) Please explain why ratepayers should be expected to pay the cost associated with incentives for any result less than the target?

e) Please explain why the award achievement range is asymmetric in that the minimum results in a 50% achievement while the maximum results in a 200% achievement.

f) Please provide an example of the calculation of the total achievement percentage using the following parameters: Spectra Energy EPS of $1.75, SET EBIT of $1,700, Union Gas EBIT of $410, SET EHS Blended Scorecard equal to the target, Union Gas Operations Scorecard equal to the target and Individual or Team set equal to the target.

g) Please define SET and SET EHS.

Response:

a) Yes. The performance achievement levels for the minimum target and maximum for 2012 are as follows:

Measure	Minimum	Target	Maximum
Spectra Energy EPS	$1.70	$1.90	$2.20
Spectra Energy Transmission (SET) EBIT ($ millions)	$1,762	$1,834	$1,975
Union Gas EBIT ($ millions)	C$390	C$402	C$426
SET Environment, Health and Safety (EHS) Blended Scorecard	Metrics updated as per past performance plus stretch		
Union Gas Operations Scorecard	Metrics updated as per past performance plus stretch		

b) The table below provides a breakdown of the 2011 total STIP payment associated with each of the measures shown in the 2011 STIP Performance Measures and Weights table on p.4 of Exhibit D1, Tab 3, Appendix B.

STIP Measure ($000's)	Breakdown
Spectra Energy EPS	5,159
Spectra Energy Transmission (SET) EBIT	5,377
Union Gas EBIT	2,888
SET ROCE	109
Union Gas ROCE	301
SET EHS Blended Scorecard	1,534
Operations Scorecard - SET	207
Operations Scorecard - Union Gas	1,830
Operations Scorecard - SET Operations	59
Operations Scorecard - SET Staff	64
Operations Scorecard - Union Gas Staff	102
Individual or Team	4,499
O&M 2010 STIP True-up	563
Total	22,692

The 2012 and 2013 macro-level forecasts are based on target (100%) payouts. For this reason, no breakdowns of the measures for these years are available.

c) The financial performance goals help focus employees on profitable growth. This means that employees are rewarded when they increase revenues by connecting new customers to natural gas, reducing costs, or provide greater levels of customer service. Union believes that focusing employees in this manner is important to ratepayers for a number of reasons:

- Ratepayers are best served by a healthy, financially capable utility that makes capital investments. Profitability creates shareholder confidence in Union, which in turn allows for new capital to provide services and infrastructure for ratepayers.

- If Union grows its base of ratepayers and natural gas usage, Union will be able to spread its fixed costs over a larger number of customers and achieve greater economies of scale.
- Union believes that customers benefit from being connected to natural gas; a clean source of energy. When new customers connect to natural gas, they are doing so having weighed the economic choices associated with their fuel alternatives.

The Environmental, Health and Safety (EHS) Scorecard reinforces the importance of safe and reliable operations while providing alignment and support to a common safety culture. The scorecard consists of several industry leading and lagging indicators that promote leadership, continuous improvement and a culture of zero injury all of which benefit Union, employees, and ratepayers.

Operations scorecards promote effective and efficient operations with measures defined in four major categories: financial, customer, process and employee.

1. **Financial Perspective**: Most measurements within this perspective are cost-focused and enable the Company to continuously improve its results on these indicators.

2. **Customer Perspective**: Union strives for operational effectiveness to achieve a mutually agreeable balance between the service level desired by customers and the cost customers are willing to pay for that service level. The measurements within this perspective are focused on customer satisfaction and include Service Quality Indicators (SQIs) such as promises kept, customer satisfaction, and gas line break frequency, drive behaviour that continuously delivers reliable and consistent service to customers.

3. **Process Perspective**: Union aspires to continually improve existing internal processes. While certain process measures are mandatory due to legislative compliance the remaining measures, such as, Emergency Response, Environmental Spills, Telephone Response, and Mean Time Between Failures, ensure Union Gas operates under consistent and repeatable processes while meeting committed SQI targets. This translates into improved efficiency of internal processes.

4. **Employee Perspective:** Union strives to create an environment that is conducive to carrying out cost-effective processes while embracing high quality and a zero injury and work-related illness culture. Safety is critical within Union Gas. The measurements within this perspective are aimed at accomplishing these priorities.

   As part of Spectra Energy, Union has a vested interest in the on-going viability of Spectra Energy. The design of the incentive plan provides alignment at the corporate level as well as line of sight at the local business unit level. Both perspectives are important to focus employees on business priorities designed to ensure financial and operational success. This in turn benefits rate payers by ensuring reliable, safe and efficient service.

d) Union's incentive plan provides payout below target for achieved results that exceed the minimum defined for each incentive measure. It is important to note that the minimum does not represent the status quo but is established based on improvement over and above historical performance. If improvement in performance is not achieved there is no incentive payment for that measure. If historical performance has been high, then these positive results are used to establish future minimum thresholds for payout. If historical results have been underperforming, a slight improvement is included to establish the new minimum threshold. After setting the minimum payout level, a stretch is added to reach the target level and a substantial stretch is built in to reach the maximum level. This methodology ensures that incentive is only paid for results that represent continuous improvement. Once optimal performance has been reached the measure may be removed from the scorecard with the employee no longer eligible for incentive pay. The payout between minimum and target provides an incentive for continuous improvement and productivity that is in the interest of the ratepayers.

e) There is significantly greater results built into the achievement of each measure from target (100%) to maximum (200%) compared to the results from minimum (50%) to target (100%). This supports and aligns with the asymmetric award achievement range. It should be stressed that the maximum payout level is only achieved with exceptional results.

f) Using the parameters provided based on 2012 weightings, the total achievement percentage would be 74.1%. The table below provides an example of the calculation of the total achievement percentage.

Measure	Weight	Sample Parameters Provided	Achievement Result Using Sample Parameters	Weighted Achievement Result
Spectra Energy EPS	20%	$1.75	62.5%	12.5%
Spectra Energy Transmission (SET) EBIT	25%	$1,700	0%	0%
Union Gas EBIT	20%	$410	133%	26.6%
SET EHS Blended Scorecard	10%	Target	100%	10.0%
Union Gas Operations Scorecard	10%	Target	100%	10.0%
Individual / Team	15%	Target	100%	15.0%
TOTAL	100%			74.1%

g) SET is defined as Spectra Energy Transmission which is defined as Spectra Energy without consideration of its joint venture DCP Midstream LLC.

SET EHS is defined as Spectra Energy Transmission Environmental Health and Safety.

UNION GAS LIMITED

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

Ref: Exhibits D3-D6, Tab 6, Schedule 1, Updated

a) Are the FTE's shown in Schedule 1 of Tab 6 in Exhibits D3 through D6 based on the regulated portion of Union Gas or do these FTE's include the unregulated business as well? If the figures include the unregulated business, please provided revised tables that reflect only the regulated business.

b) Please explain the type of employees that are included in the Management category. In additions to Vice-Presidents, Directors, Managers and Team Leaders (as shown in Exhibit A1, Tab 10), what other types of employees are included?

c) Please provide a further breakdown of the Management category for 2010 through 2013 into Executive, Directors, Managers and Other Management. If necessary for confidentiality purposes, two of the proposed categories can be merged into one.

Response:

a) The FTEs shown in Schedule 1 of Tab 6 in Exhibit D3 through D6 include all of Union's FTEs (related to both regulated and unregulated activities). Union does not track FTE data based on regulated and unregulated activities separately.

b) In addition to Vice-Presidents, Directors, Managers and Team Leaders, the management category includes senior technical and professional level roles such as engineers, accountants, information technology, and operations.

c) Categories available for presentation are Executive, Management, Analyst, Unionized and Non-Unionized. FTEs and salary data are not tracked by Union in the categories requested.

   Please see J.D-9-2-1 Attachment 1 for 2010-2013 data based on the categories above.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 6, Schedules 1 & 2, Updated

a) If the table includes FTE's associated with the unregulated business, please provide a table that includes 2011 actual data for the regulated business only.

b) Please provide the actual number of vacancies in each of 2007 through 2011.

c) Please explain how the 69 vacancies forecast for 2013 have been reflected in the calculations of the averages shown in Schedule 1 of Exhibit D3, Tab 6, Updated. In particular, have the costs associated with the 69 vacancies been included in the total salaries, variable pay and benefit costs? If yes, please explain why these costs should be included.

d) Have any costs associated with the 69 vacant positions in 2013 been included in O&M and/or Capital components included in the 2013 revenue requirement? If yes, please explain why.

e) Please provide the total number of FTE's for each of 2007, 2008 and 2009 that are comparable to the 2,211 shown for 2010.

Response:

a) Please see the response at Exhibit J.D-1-2-3.

b)

Actual Number of Vacancies

2007	2008	2009	2010	2011
59	60	63	63	66

c) The costs associated with the 69 vacancies have not been included in the averages shown in Schedule 1 of Exhibit D3, Tab 6 Updated for total salaries, variable pay and benefit costs.

d) Costs associated with the 69 assumed vacancies in 2013 have not been included in the O&M and Capital components of the 2013 revenue requirement.

e) Please see the response at Exhibit J.D-1-2-3 b).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Appendix A &
Exhibit D3-D6, Tab 6, Schedule 1/2

Please provide comprehensive summary tabulation of Total Compensation 2007-2013 for the 4 groups of employees listed in the Towers Watson Letter:

Executives, Managers, Salaried Professionals, Unionized Employees

- # incumbents (FTE end of Year). Also indicate # temp and part time
- Average Compensation
- Base Pay
- Incentive Pay Standard bonus and STIP
- Benefits
- Totals for each component of TC- Salary Incentive Pay Benefits
- Total Compensation (reconciled to O&M expense for year)

Response:

Categories available for presentation are Executive, Management, Analyst, Unionized and Non-Unionized. O&M salary data is not tracked by Union Gas in the categories requested.
Please see Attachment 1 to 3 for 2007-2013 requested data based on the categories above.
Notes:

- “Total Salaries” includes both Base Pay and Overtime Pay
- “Total Variable Pay” includes both Short Term and Long Term Incentive Plans (STIP & LTIP). These represent the “Incentive Pay Standard bonuses” at Union Gas.
- All FTE data is based on end of year amounts.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2007

Line No.	Particular	FTE	($000's) Total Salaries (1)	Total Variable Pay (2)	Total Benefit
		(a)	(b)	(c)	(d)
1	Executive	7	1,806	1,551	330
2	Management	845	70,640	10,116	23,727
3	Analyst	234	15,618	919	5,938
4	Unionized	938	60,868	1,552	23,374
5	Non-Unionized	123	7,235	390	2,945
6	Total	2,147	156,168	14,528	56,314

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	526,774	258,004	221,625	47,145
8	Management	123,604	83,568	11,967	28,069
9	Analyst	95,883	66,631	3,922	25,331
10	Unionized	91,514	64,926	1,656	24,932
11	Non-Unionized	86,011	58,873	3,173	23,965
12	Average	105,729	72,735	6,766	26,228

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2008

Line No.	Particulars	FTE	Total Salaries [1] ($000's)	Total Variable Pay [2] ($000's)	Total Benefit ($000's)
		(a)	(b)	(c)	(d)
1	Executive	5	2,008	1,875	300
2	Management	878	74,800	13,211	22,246
3	Analyst	267	17,546	1,323	5,944
4	Unionized	933	64,695	1,722	20,393
5	Non-Unionized	118	8,794	447	2,456
6	Total	2,201	167,843	18,578	51,340

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	836,682	401,557	375,074	60,051
8	Management	125,650	85,243	15,056	25,351
9	Analyst	92,932	65,716	4,953	22,262
10	Unionized	93,043	69,341	1,845	21,858
11	Non-Unionized	99,042	74,461	3,782	20,799
12	Average	108,044	76,271	8,442	23,330

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2009

Line No.	Particulars	FTE	Total Salaries (1) ($000's)	Total Variable Pay (2) ($000's)	Total Benefit ($000's)
		(a)	(b)	(c)	(d)
1	Executive	7	2,228	1,659	344
2	Management	910	79,901	11,667	23,635
3	Analyst	272	17,491	1,165	6,272
4	Unionized	899	60,729	1,432	20,415
5	Non-Unionized	95	8,168	329	2,058
6	Total	2,183	168,517	16,252	52,723

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	604,528	318,352	237,051	49,125
8	Management	126,555	87,774	12,817	25,964
9	Analyst	91,646	64,304	4,283	23,059
10	Unionized	91,863	67,560	1,593	22,711
11	Non-Unionized	111,213	86,065	3,467	21,681
12	Average	108,787	77,192	7,444	24,151

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2010

Line No.	Particulars	FTE	Total Salaries [1] ($000's)	Total Variable Pay [2] ($000's)	Total Benefit ($000's)
		(a)	(b)	(c)	(d)
1	Executive	7	1,978	2,177	382
2	Management	956	83,902	16,705	32,540
3	Analyst	276	18,269	1,615	8,437
4	Unionized	884	63,203	1,851	26,769
5	Non-Unionized	88	4,480	422	2,549
6	Total	2,211	171,832	22,770 [3]	70,677

Line No.	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	648,278	282,608	311,033	54,636
8	Management	139,304	87,782	17,477	34,045
9	Analyst	102,536	66,143	5,846	30,547
10	Unionized	103,871	71,496	2,093	30,282
11	Non-Unionized	84,937	51,071	4,810	29,056
12	Average	119,996	77,727	10,300	31,970

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.
(3) "Total Variable Pay" has been corrected from the filed evidence for 2010

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2011

Line No.	Particulars	FTE	Total Salaries [1] ($000's)	Total Variable Pay [2] ($000's)	Total Benefit ($000's)
		(a)	(b)	(c)	(d)
1	Executive	7	2,083	2,531	424
2	Management	1,003	90,883	17,997	36,138
3	Analyst	261	16,223	1,763	10,568
4	Unionized	881	66,877	2,458	30,707
5	Non-Unionized	67	3,656	461	3,217
6	Total	2,219	179,722	25,210	81,054

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	719,796	297,572	361,632	60,592
8	Management	144,606	90,625	17,946	36,035
9	Analyst	109,572	62,252	6,766	40,554
10	Unionized	113,534	75,897	2,789	34,848
11	Non-Unionized	110,050	54,858	6,912	48,280
12	Average	128,866	80,983	11,360	36,523

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2012

Line No.	Particulars	FTE	($000's) Total Salaries [1]	Total Variable Pay [2]	Total Benefit [3]
		(a)	(b)	(c)	(d)
1	Executive	7	2,166	2,527	434
2	Management	1,030	93,378	12,924	37,651
3	Analyst	277	17,306	971	9,022
4	Unionized	914	65,134	1,604	29,384
5	Non-Unionized	91	4,456	302	2,792
6	Total	2,319	182,439	18,328	79,283

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	732,270	309,385	360,940	61,945
8	Management	139,707	90,622	12,541	36,544
9	Analyst	98,690	62,566	3,510	32,614
10	Unionized	105,156	71,255	1,755	32,146
11	Non-Unionized	83,039	49,013	3,321	30,705
12	Average	120,764	78,671	7,903	34,189

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.
(3) "Total Benefit" includes Pension reported on a US GAAP basis.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2013

Line No.	Particulars	FTE	($000's) Total Salaries [1]	Total Variable Pay [2]	Total Benefit [3]
		(a)	(b)	(c)	(d)
1	Executive	7	2,240	2,804	448
2	Management	1,031	96,471	13,250	38,897
3	Analyst	274	17,928	1,004	9,015
4	Unionized	914	67,244	1,659	29,657
5	Non-Unionized	91	4,608	313	2,794
6	Total	2,317	188,491	19,030	80,811

Line No.	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
7	Executive	784,579	319,982	400,587	64,010
8	Management	144,156	93,575	12,852	37,729
9	Analyst	101,874	65,336	3,660	32,878
10	Unionized	107,866	73,593	1,816	32,457
11	Non-Unionized	84,846	50,679	3,437	30,730
12	Average	124,440	81,351	8,213	34,876

Notes:

(1) "Total Salaries" include both O&M and Capital related salaries.
(2) "Total Variable Pay" includes both short term and long term incentive plans.
(3) "Total Benefit" includes Pension reported on a US GAAP basis.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Reconciliation to O&M Expense
Calendar Years Ended December 31, 2007-2013
in $000s

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Salaries & Wages (incld. Var Pay)							
Total Salaries (previous schedules)	156,168	167,843	168,517	171,832	179,722	182,439	188,491
Total Variable Pay (previous schedules)	14,528	18,578	16,252	22,770	25,210	18,328	19,030
Other Labour	10,134	5,923	6,404	3,458	3,831	2,897	2,450
Total Salaries and Wages	180,831	192,344	191,173	198,061	208,763	203,664	209,972
Less: Capital related S&W	(16,459)	(20,070)	(16,108)	(14,812)	(16,926)	(15,714)	(16,185)
Total Salaries and Wages - O&M	164,371	172,274	175,066	183,249	191,837	187,950	193,786

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Benefits							
Total Benefits (previous schedules)	56,314	51,340	52,723	70,677	81,054	79,283	80,811
Non HR Related Benefits	51	27	196	185	124	269	272
US GAAP (Pension)	0	0	0	0	0	2,610	0
Total Benefits - O&M	56,365	51,366	52,919	70,861	81,179	82,161	81,083

UNION GAS LIMITED
Total FTEs
Breakdown of FTE Type
Calendar Years Ended December 31, 2007-2013

Employee Type	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Full Time	2,023	2,050	2,065	2,076	2,090	2,171	2,177
Part Time	58	60	64	67	71	71	67
Temporary/Seasonal	66	91	54	68	58	77	73
Total FTE	2,147	2,201	2,183	2,211	2,219	2,319	2,317

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Page 7

To validate the competitiveness of its programs, Union compares its programs to a cross-section of national companies of similar revenue size, including energy utilities as well as organizations with operations in Ontario.

Please provide the latest Salary/compensation/benefits comparison study(ies).

Response:

Union completes a review of its pension, benefits and compensation programs on an annual basis. This review is completed in conjunction with Towers Watson and/or based on Towers Watson's survey results. To further validate the competitiveness of its programs and ensure they are appropriately positioned, Union periodically commissions Towers Watson to conduct benchmarking of its programs versus the programs offered by competitors. Towers Watson uses several sources of comparative information to complete this benchmarking including data from its own proprietary database to complete the analysis.

With respect to benefits, Union recently retained Towers Watson to conduct a benchmarking review of its programs. The results of this review indicate that the employer-provided values of Union's benefits programs falls within the competitive range of the average of the employer – provided values of the comparator group of companies. Please see Attachment 1 for a summary of the findings.

Please see the response at Exhibit J.D-9-2-4. Towers Watson updated its letter to reflect 2011 as the base year for its compensation analysis.

TOWERS WATSON

Ashley Witts MA, FIA, FCIA, FSA
Account Director

1100 Melville Street
Suite 1600
Vancouver, British Columbia
V6E 4A6

T +1 604 691 1000
D +1 604 691 1007
C +1 604 506 9056
F +1 604 691 1062

ashley.witts@towerswatson.com
towerswatson.com

Private & Confidential

April 24, 2012

Mr. Rick DeBoer
Manager, Benefits Planning & Delivery
Spectra Energy Transmission
50 Keil Drive North
Chatham, ON N7M 5M1

Dear Rick,

COMPETITIVE STUDY OF UNION GAS' BENEFIT PROGRAMS

The attached document provides the results of the most recent competitive analysis of Spectra Energy's/Union Gas' benefit programs undertaken in October 2010.

The competitive analysis was prepared using Towers Watson's standard actuarial methodology and assumptions. Using this methodology, the actuarial values of each organization's benefits programs are calculated and adjusted for any required employee contributions to determine the employer-provided values of the programs. The results are presented as an index of values with the average employer-provided index value set at 100.

Union's programs are shown as the red bar in the attached bar chart summarizing the results of the analysis. These results indicate that the employer-provided value of Union's benefits programs falls within the competitive range of the average of the employer-provided values of the comparator group of companies. The comparator group comprises a cross-section of national companies of similar size as well as other energy utilities and organizations with operations in Ontario.

The approach and methodology described above is the same as that adopted by Union in preparing competitive analyses since at least 2001.

Please let me know if you have any questions.

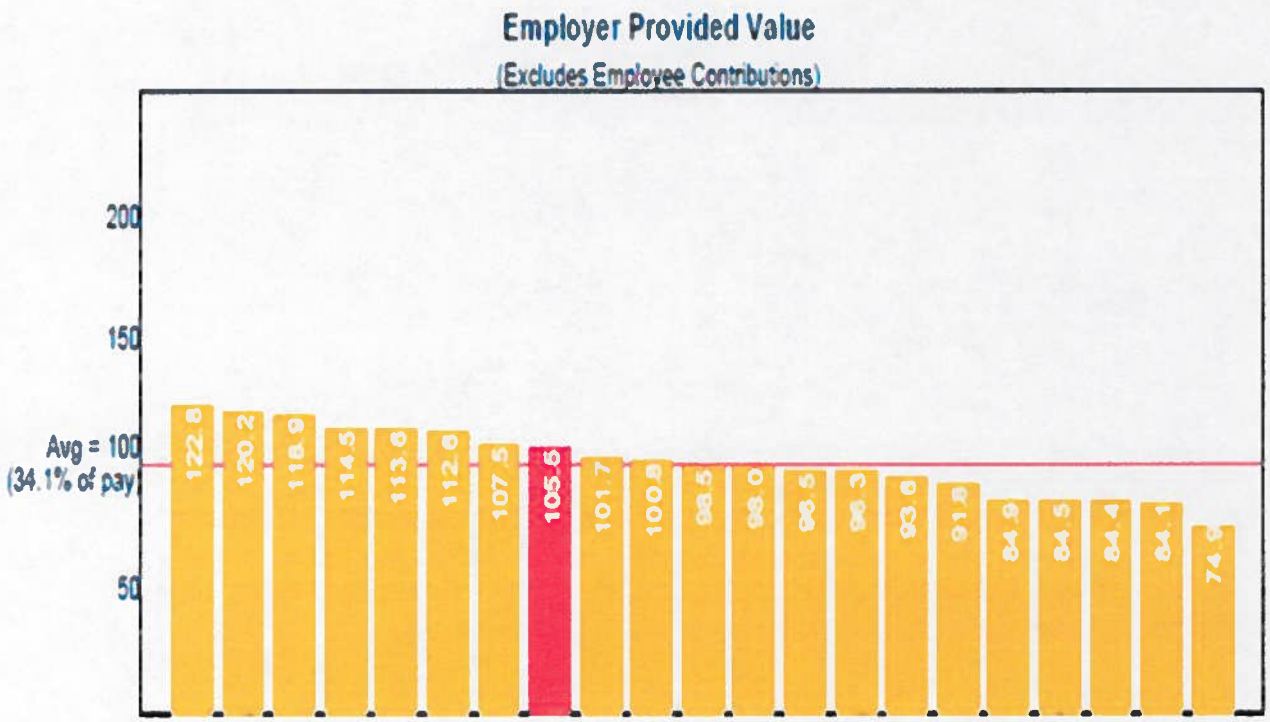
Sincerely,

Ashley Witts
Account Director

Spectra Energy

Competitiveness of Benefit Programs

Benefits Competitiveness Index



Spectra Energy Benefits Comparator Group

Spectra Energy

- ATCO Group
- BC Hydro
- Bruce Power
- Enbridge Gas Distribution Inc.
- Enbridge Pipelines Inc.
- EnCana Corporation
- Finning International Inc.
- Gaz Metro Limited Partnership
- Imperial Oil Limited
- Ontario Power Generation Inc.
- Shell Canada Limited
- **Spectra Energy Transmission**
- Suncor Energy Inc.
- Syncrude Canada Inc.
- Talisman Energy Inc.
- Teck Resources Limited
- TELUS Corporation
- Terasen Gas Inc. (now Fortis BC Energy)
- TransAlta Corporation
- TransCanada PipeLines Limited
- Vale Inco Limited

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Page 5

As mentioned previously, approximately 30 executive and leadership employees at Union participate in an additional variable pay plan.

a) Please provide details of LTIP PSUs and Phantom Stock Units 2007-2013 # grants, $ amounts and outstanding units and cost.

b) Please provide average strike price for each historic year and forecast for 2012 and 2013.

c) Reconcile to Total Compensation cost for 2013.

Response:

a)

Performance	Granted (shares)	Fair Value (millions)	Outstanding as of end of Period	Fair Value (millions)
2007	-	-	34,182	$0.1
2008	51,500	$1.6	60,257	$1.8
2009	67,600	$1.0	111,155	$2.4
2010	59,400	$1.8	165,987	$4.1
2011	63,600	$2.0	184,669	$4.7
2012	53,500	$2.2	n/a	n/a

Phantom	Granted	Fair Value (millions)	Outstanding as of end of Period	Fair Value (millions)
2007	32,700	$0.8	48,762	$1.2
2008	47,600	$1.2	77,909	$1.9
2009	63,000	$0.8	135,265	$2.6
2010	65,600	$1.4	165,736	$3.2
2011	47,200	$1.2	170,109	$3.4
2012	25,000	$0.8	n/a	n/a

Figures are in US Dollars.
For 2013, outstanding units and costs for end of period are unavailable since the 2012 period has not ended.
For 2013, actual number of units granted will be determined based on the stock price at the time of the grant.
Currently, $3.3 million is budgeted for 2013 awards.

b) Union has not pursued granted stock options since 2007 and is not forecasting granting options in 2012 or 2013. In 2007, the strike price for the majority of grants was $25.64 (USD).

c) Please see reconciliation of 2013 total compensation cost in the response at Exhibit J.D-9-3-1. The LTIP amount of $3.3 million is included in the Variable Pay amount.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Appendix A

a) Summarize Union's Proposed S&W increases (Base Pay and incentives) for each of the 4 groups for 2011 (actual), 2012 forecast and 2013 forecast.

b) Has Towers Watson opined on these increases, given the larger picture of public sector wage settlements and Union's 2013 revenue requirement and rate increases?

c) Please provide the Sensitivity for 2013 to a 300 basis point (0.3%) change in average compensation.
   i. Total Compensation cost and
   ii. Overall O&M

Response:

a) Please see Attachment 1. The chart summarizes the proposed salary and wage increases (Base Pay and Incentives) for each of the 4 groups.

b) No.

c)
i. A change of 0.3% in average compensation will change total net utility compensation costs (salaries, wages, incentives, benefits) by $0.5 million.

ii. Please see the response at part i) above. Since salaries, wages, incentives, and benefits are only impacted, this change would result in the same $0.5 million change.

	2011				**2012**				**2013 (Forecast)**			
	Executives	Managers	Salaried Professionals	Unionized	Executives	Managers	Salaried Professionals	Unionized	Executives	Managers	Salaried Professionals	Unionized
Average Base Salary %	2.9%	3.2%	2.9%	3.0%	2.3%	3.1%	2.9%	3.0%	3.5%	3.5%	3.5%	3.0%
Average Incentive Pay %	34.2%	14.1%	8.4%	2.5%	37.5%*	14.2%*	8.3%*	2.5%*	N/A	N/A	N/A	2.5%

* Estimate

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 3, Page 15 &
Exhibit D3, Tab 6, Schedule 1 / 2

At Union, 44% of existing employees will be eligible to retire within the next five years.

a) Please provide the profile of Retirements by the 4 job/compensation types historic 2007-2011 and forecast 2012-17.
b) How do retirements affect the average vacancy rate of 69 FTEs?

c) Separate the 2011 actual FTE and Vacancy data for the regulated and unregulated businesses.

Response:

a)

Group	2007	2008	2009	2010	2011	Total
Management	4	5	8	8	9	34
Salaried Professionals	8	10	11	19	29	77
Unionized	25	40	23	33	39	160
Total	37	55	42	60	77	271

Forecasts have not been developed for these categories of employees.

b) At any point in time there are approximately 69 FTE vacancies within Union. These vacancies are related to retirements, general attrition and turnover within specific job classifications.

c) Please see the response at Exhibit J.D-1-2-3 d).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 7, Appendix A [HR Benchmarking]

HR – Benchmark comparisons indicate that Union has a lower total cost of the HR function as per $1,000 revenue than the majority of the utilities in the industry. When compared against respondents within a similar revenue range and region, Union is in line with the median.

a) Please explain why HR costs are at Median but in Supplemental Benchmarking HR Function is below 25th percentile, i.e. expensive per Employee at $2,414 (2010).

b) Please update the forecast HR Cost per employee for 2013.

Response:

a) As indicated at p.3 of KPMG's report (Exhibit D1, Tab 7, Appendix A) the most relevant benchmarks are cost measures rather than the process efficiency measures provided in the supplemental information. As noted at p. 33 of the report, Union's HR department is "an experienced and long standing service team that is remunerated accordingly, which may lead to higher personnel costs". The report also notes that additional staff is required to "service diverse needs and customize programs" across Union's service territory. This could also contribute to the higher cost per employee. Union is not aware of the size of firms in the utility peer group (page 20). Union does know that all types of utilities (gas, water and electric) are included.

b) The estimated figures for 2013 are as follows:

Total personnel cost of the HR function per employee: $2,300
Total HR cost per business entity FTE (excludes benefits program cost) : $1,900

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit A2, Tab 3, Schedule 1, Appendix B, page 6

Please explain how the 3% vacancy rate was derived. How is that rate applied to the budget?

Response:

The 3% vacancy rate is based on historical vacancy experience. As part of the budget process, salary and wage budgets are reduced by the vacancy rate, with the exception of utility service representative and customer call centre positions. Due to the expeditious manner in which these vacancies are filled, Union applies no vacancy rate in the budget for these employee groups.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 4

Projected salary and wage increases are 3% for 2012 and 3.5% for 2013. What is the basis for this assumption?

Response:

Base salary budgets are set with primary consideration given to Towers Watson's forecasts of salary increases, negotiated wage settlements and consumer price index projections. Secondary consideration is given to labour market survey forecasts from other Human Resource Consulting Firms.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 9

Please provide a schedule setting out FTEs for the years 2007 to 2013. For 2007 please include the Board approved numbers.

Response:

Please see Attachment 1.

Union Gas Limited
2007 to 2013 FTE

Line No.	Particulars	Board Filed 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
1	Total	2,201	2,147	2,201	2,183	2,211	2,219	2,319	2,317
2	Assumed Vacancies in Forecast	(66)						(69)	(69)
3	Total	2,135	2,147	2,201	2,183	2,211	2,219	2,250	2,248

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 3, page 5

Please provide all internal documentation that describes the Long-Term Incentive Program. How has the program changed since 2007?

Response:

Please see Attachment 1 for a copy of the most recent Long-Term Incentive Program ("LTIP") brochure.

In 2007, the LTIP program consisted of two types of awards: stock options and phantom stock units, with each type of award accounting for 50% of the participants' LTIP opportunity. Beginning in 2008, the LTIP program consisted of performance share units and phantom stock units, with each type of award accounting for fifty percent of the participants' LTIP opportunity. Effective for 2011, performance share units account for 60% of the participants' LTIP opportunity and phantom share units account for 40%. Stock options are vested incrementally over a three-year period, during continuous employment. All performance share units are subject to vesting, but only after a specified performance goal relative to a peer group of energy companies has been achieved, during continuous employment. All phantom stock units cliff vest on the third anniversary of the grant date, during continuous employment.

Spectra Energy

Spectra Energy Corp

Long-Term Incentive Program

2012

Table of Contents

This brochure is a general summary of the 2012 Spectra Energy Long-Term Incentive Program. Awards are granted under the provisions of the Spectra Energy Corp 2007 Long-Term Incentive Plan, as amended and restated (Plan), and information in this brochure should be read together with the award agreements and the Plan. In case of any questions of interpretation, provisions of the agreements and the Plan govern. Spectra Energy Corp reserves the right to amend, suspend or terminate the Plan at any time and for any reason. **Participation in the Spectra Energy LTI program is not an offer or guarantee of employment or an employment contract and does not alter the at-will nature of any employee's employment in any way.**

Spectra Energy's objective is to motivate and reward its leaders through a variety of compensation arrangements. Stock and stock-based awards are an important part of providing leaders with a long-term component of total compensation that is intended to:

- Directly align leaders' economic interests with shareholders,
- Make compensation contingent on achieving strategic goals,
- Provide opportunities for real share ownership by leaders, and
- Retain leadership talent.

The purpose of this brochure is to acquaint you with the 2012 Spectra Energy Corp Long-Term Incentive (LTI) Program and how it works. Because participation in the 2012 LTI Program has significant financial implications, we encourage you to carefully read this brochure in conjunction with your award agreements and the 2007 Spectra Energy Corp Long-Term Incentive Plan document. We also recommend that you discuss this information with your personal financial advisor.

Eligibility

The Compensation Committee of the Board of Directors of Spectra Energy, or its designee, determines your eligibility to participate in the 2012 LTI Program. If you are eligible to participate in 2012, you will have received information about your 2012 LTI opportunity either directly from your manager or the Executive Compensation department.

Award Design

Sixty percent of your 2012 LTI opportunity consists of performance share units and forty percent consists of phantom stock units. The grant date for the annual 2012 award is February 21, 2012. (Off-cycle grants are made at the beginning of each calendar quarter if an award is being made in connection with commencement of employment, a promotion, or some other special circumstance.) Specific provisions of your awards are provided in your grant notification letter and in your award agreements.

Award Acceptance

In order for your 2012 LTI awards to take effect, it will be necessary for you to accept the awards and agree to be bound by their terms. An email communication with detailed instructions will be sent to you when it is time to accept your stock-based awards.

Performance Share Units – Features

The goal of your performance share units is to link the delivery of a portion of your long-term incentive value to achievement of a performance goal that is directly aligned with shareholders – Spectra Energy's TSR (Total Shareholder Return) relative to the TSR of a Peer Group of companies for the three calendar-year period beginning on January 1, 2012 and ending on December 31, 2014.

Normal Vesting

In order for performance share units to vest, you must be employed on the last day of the performance period, and the Compensation Committee of the Board of Directors must certify the degree to which the performance goal has been achieved.

The chart below indicates the percentage of the performance share units in your award that will vest, based on a determination of achievement of Spectra Energy's TSR relative to that of the Peer Group of companies, measured over the three calendar-year period, at the percentile ranking specified.

Spectra Energy's TSR Percentile Ranking vs. Peer Group	% of Award Shares Vested
Below 30th	**0%**
30th (minimum)	**50%**
50th (target)	**100%**
80th or higher (maximum)	**200%**

Payout for performance between the 30th and 50th percentile and the 50th and 80th percentile will be interpolated on a straight-line basis.

The Committee may reduce or eliminate any vesting that would otherwise occur if Spectra Energy's TSR, for the three calendar-year period, is negative.

Half of the vested performance share units are paid in cash based upon the fair market value of Spectra Energy common stock. The other half of the vested performance share units are paid in whole shares of Spectra Energy common stock.

Dividend Equivalents

Following the determination in early 2015 that the three-year TSR goal has been achieved, unless payment upon vesting has been deferred, you will receive a dividend equivalent cash payment for each vested performance share unit (including the performance share units to be paid in cash). This payment is equal to the cash dividends declared and paid on one share of Spectra Energy common stock during the period that begins on the grant date and ends when the share is vested and paid. Dividend equivalents are subject to income and employment tax withholding.

Stock Ownership

Because you are a participant in the 2012 Long-Term Incentive Program, you are expected to accumulate ownership of Spectra Energy shares according to the ownership policy adopted by our Board of Directors.

Unvested performance share units do not count toward your Spectra Energy stock ownership level. Actual shares of Spectra Energy common stock paid to you and held after your performance share units vest do count toward your Spectra Energy stock ownership level. Vested performance share units paid out in cash do not count toward your Spectra Energy stock ownership level.

Voting Rights

Your performance share units do not give you shareholder voting rights since no actual shares are issued to you unless and until the performance share units vest and are paid in stock.

Ability to Sell

You may not sell your performance share units, but you can sell the shares of Spectra Energy common stock that you receive following vesting and payment of the performance share units, subject to limitations under insider trading regulations.

Tax Considerations

Under U.S. and Canadian tax rules, you will have taxable income when your performance share units are paid to you in stock or cash. This income will be shown on your IRS Form W-2 if you are a U.S. citizen or resident, and on your T-4 form if you are a Canadian resident. Federal income tax and any applicable state, provincial, local, Social Security and Medicare tax withholding must be collected upon the payment of your performance share units.

Regarding performance share units paid in cash, the amount paid to you will be equal to the number of units vested at the fair market value of the stock on the payment date. This payment and the related tax withholding will be processed via your regular paycheck.

Regarding performance share units paid in stock, the amount of taxable income and the value of the shares used to pay your tax withholding obligation is based on the fair market value of the stock on the payment date. The number of shares issued to you will be reduced in order to satisfy your tax withholding obligation; therefore, you will receive the number of shares that have vested less the shares used to pay your tax withholding.

Keep in mind that your income will be taxed at supplemental withholding rates, and you may later owe additional income taxes depending upon your personal financial situation. Consult your tax advisor to determine whether you should make an additional estimated tax payment.

Total Shareholder Return (TSR)

Total shareholder return (TSR) is a measure of increase or decrease in the value of an investment realized by shareholders over a measurement period assuming dividends are reinvested. For 2012 awards, TSR will be calculated over a three-year measurement period for Spectra Energy and for each company in the Peer Group, and the percentile ranking of Spectra Energy's TSR as compared to the Peer Group will determine the vesting percentage.

TSR Calculation

For Spectra Energy and each Peer Group company, the value of a share at the beginning of the measurement period is calculated as the average closing price of the 20 consecutive trading dates ending on December 31, 2011, and the value of a share at the end of the measurement period is calculated as the average closing price of the 20 consecutive trading dates ending on December 31, 2014. TSR is calculated using these average prices and reinvested dividends assuming dividends are reinvested in shares on the dividend payment date. Due to the potential volatility in the stock market, using a 20-day average for the beginning and the end of the measurement period should provide a reliable reflection of each company's performance and avoid causing the performance goal being achieved or missed due to short-term anomalies. An example of a TSR calculation over a one-year period is as follows:

Month	Share Value	Dividend Reinvestment**	Total Shares
Jan 1	$20.00*	Not applicable	Initial Investment of 100 shares = **$2,000**
Mar	$21.00	100 shares x $0.21 = $21.00	Buy 1 share = 101 shares
June	$21.21	101 shares x $0.21 = $21.21	Buy 1 share = 102 shares
Sept	$21.42	102 shares x $0.21 = $21.42	Buy 1 share = 103 shares
Dec	$21.63	103 shares x $0.21 = $21.63	Buy 1 share = 104 shares
Dec 31	$22.00*	Not applicable	104 shares x $22.00 = **$2,288**
Total Shareholder Return = ($2,288 - $2,000) / $2,000 = **14.4%**			

**Average closing share price of a share on the twenty consecutive trading days ending December 31.*

***Quarterly cash dividend assumed to be $0.21 per share for illustration purposes only.*

Peer Group Companies

There are 20 companies in the Peer Group. The following group of companies was chosen as the comparator group because it is comprised of companies with significant pipeline assets, or companies with a portion of their revenues derived from gas transmission and/or gas distribution activities.

Peer Group Companies	
Ameren Corporation (AEE)	NiSource Inc (NI)
CenterPoint Energy (CNP)	ONEOK, Inc. (OKE)
Consolidated Edison (ED)	PG&E Corp. (PCG)
Dominion Resources (D)	Public Service Enterprise (PEG)
DTE Energy Company (DTE)	Questar Corp. (STR)
El Paso Corporation (EP)	Sempra Energy (SRE)
Enbridge Inc (ENB)	Southern Union (SUG)
EQT Corporation (EQT)	The Williams Cos. (WMB)
Kinder Morgan (KMI)	TransCanada Corp. (TRP)
National Fuel Gas Co (NFG)	Xcel Energy Inc (XEL)

How Peer Group Company Changes Affect TSR Percentile Ranking

Management and the Committee recognize that changes can occur to the companies in the Peer Group during the measurement period. Changes to Peer Group companies and how they will affect the performance ranking of the companies are as follows:

- If a Peer Group company is not publicly traded at the end of the performance period, it will not be used in calculating the Peer Group's TSR. However, if a Peer Group company is not publicly traded because of a bankruptcy, its performance will be included in the TSR calculation.
- In the event there is a combination of any Peer Group companies, the surviving entity's performance will be used.
- No new companies will be added to the Peer Group, including a non-peer company acquiring a member of the Peer Group.

Normal Vesting

Your phantom stock units vest according to a cliff-based vesting schedule. Under this schedule, all (100%) of your phantom stock units will vest on the third anniversary of the grant date, provided that you remain continuously employed by Spectra Energy through that date. Vested phantom stock units are paid in whole shares of Spectra Energy common stock and are paid as soon as practicable after they vest.

Dividend Equivalents

You will receive a dividend equivalent payment in 2015 on your phantom stock units that vest, unless payment upon vesting has been deferred. The dividend equivalent payment for each vested phantom stock unit will equal the cash dividends declared and paid on one share of Spectra Energy common stock during the period that begins on the grant date and that ends when the unit is vested and paid. Dividend equivalents are subject to income and employment tax withholding.

Stock Ownership

Your unvested phantom stock units, and shares of Spectra Energy common stock that you receive following vesting and continue to hold, count toward your Spectra Energy stock ownership level.

Voting Rights

Your phantom stock units do not give you shareholder voting rights since no actual shares are issued to you unless and until the phantom stock units vest and are paid.

Ability to Sell

You may not sell your phantom stock units, but you can sell the shares of Spectra Energy common stock that you receive following vesting and payment of the units, subject to limitations under insider trading regulations.

Tax Considerations

Under U.S. and Canadian tax rules, you will have taxable income when your phantom stock units are paid to you based on the fair market value of the common stock issued at such time. This income will be shown on your IRS Form W-2 if you are a U.S. citizen or resident, and on your T-4 form if you are a Canadian resident. Federal income tax and any applicable state, provincial, local, Social Security and Medicare tax withholding must be collected upon the payment of your phantom stock units.

The number of shares of Spectra Energy common stock that would otherwise be paid to you will be reduced in order to satisfy your tax withholding. The shares used to pay your tax withholding are valued at the fair market value on the payment date, and you will receive the number of shares that have vested less the shares used to pay your tax withholding shortly after your tax withholding obligation is satisfied.

Keep in mind that your income will be taxed at supplemental withholding rates, and you may owe additional income taxes depending upon your personal financial situation. Consult your tax advisor to determine whether you should make an additional estimated tax payment.

2012 LTI Program Summary Chart

The following chart summarizes the terms of your stock-based award opportunities under the 2012 LTI Program.

Provision	Performance Share Units	Phantom Stock Units
Grant date	Annual Award: February 21, 2012 Off-cycle Awards: Specified in award document	Annual Award: February 21, 2012 Off-cycle Awards: Specified in award document
Vesting Period		
• While employment continues	Following determination in early 2015 that the three-year relative TSR goal has been achieved, immediate vesting of the applicable number of shares based on performance.	Three-year cliff vesting – 100% vesting on the third anniversary of the grant date (For annual awards: February 21, 2015).
• Upon retirement	If after 12/31/14, vesting of applicable number of performance share units based on Spectra Energy's TSR relative to Peer Group. If on or before 12/31/14, performance share units awarded are reduced to reflect only full and partial months of service during the measurement period. Pro-rated shares vest based on TSR performance over the entire three-year measurement period as determined in early 2015.	Units awarded are reduced to reflect only full and partial months of service during the vesting period. The pro-rated award vests on the third anniversary of the grant date (For annual awards: February 21, 2015). The remaining units are forfeited.
• Upon death/ disability	If after 12/31/14, vesting of applicable number of performance share units based on Spectra Energy's TSR relative to Peer Group. If on or before 12/31/14, vesting of performance share units assuming target (100%) performance.	100% vesting of outstanding, unvested units. However, any vested units may not be released until six (6) months following your separation from service, unless your separation from service results from death.
• Upon involuntary termination, without cause	If after 12/31/14, vesting of applicable number of performance share units based on Spectra Energy's TSR relative to Peer Group. If on or before 12/31/14, performance share units awarded are reduced to reflect only full and partial months of service during the measurement period. Pro-rated shares vest based on TSR performance over the entire three-year measurement period as determined in early 2015.	Units awarded are reduced to reflect only full and partial months of service during the vesting period, and such pro-rated units vest. However, any vested units may not be released until six (6) months following your separation from service. The remaining units are forfeited.
• Upon involuntary termination, for cause, or • Upon voluntary termination	If after 12/31/14, vesting of applicable number of performance share units based on Spectra Energy's TSR relative to Peer Group. If on or before 12/31/14, all unvested performance share units are forfeited.	Vesting ends and all unvested units are forfeited.
• Upon a Change in Control	If after 12/31/14, vesting of applicable number of performance share units based on Spectra Energy's TSR relative to Peer Group. If on or before 12/31/14, vesting of performance share units assuming target (100%) performance.	100% vesting of outstanding, unvested units if, within two years following Change in Control, employment is terminated involuntarily by the successor company without cause or for Good Reason. However, any vested units may not be released until six (6) months following your separation from service.
• During Approved, Unpaid Leave of Absence	Vesting continues during the period of leave.	Vesting continues during the period of leave.
Dividend Equivalents	Paid upon vesting in an amount equal to the aggregate cash dividends declared and paid, after the grant date and before the vested performance share unit is paid, on a share of Spectra Energy common stock.	Paid when shares are released in an amount equal to the aggregate cash dividends declared and paid, after the grant date and before the vested phantom unit is paid, on a share of Spectra Energy common stock.

New LTI Participants

If you are a new participant in the LTI Program, you will receive an email from Morgan Stanley Smith Barney at your Company email address regarding your Morgan Stanley Smith Barney Benefit Access account. The email will include a personalized Internet link that, when clicked, will take you to a secure web page to activate your account. Once your account is active, you may view your LTI awards and commence transactions immediately.

Resources

Questions should be directed to Morgan Stanley Smith Barney's Customer Call Center. The call center will be able to help with many types of questions, including:

- General inquiries
- Processing transactions, such as exercising options
- Benefit Access account questions and activation
- Spectra Energy long-term incentive plan provisions

Morgan Stanley Smith Barney's Customer Call Center
Monday through Friday 8:00 a.m. – 8:00 p.m. (EST)
Toll-Free: 866-375-6950
Direct/International: 210-677-3611

If you have questions about the 2012 LTI Program, you may contact:

Stephanie McCall
Director, Executive Compensation
713-627-4105
smmccall@spectraenergy.com

Karen Gowder
Executive Compensation Analyst
713-627-5394
krgowder@spectraenergy.com

If you have questions regarding securities law restrictions, you may contact:

Christopher Agbe-Davies
Associate General Counsel
713-627-5385
ckagbedavies@spectraenergy.com

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 3, page 6

What is the cost of the LTIP included in the 2013 revenue requirement?

Response:

The cost of LTIP included in the 2013 revenue requirement is $3.3 million.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 3, page 6

Please provide a schedule setting out the following for each year 2007-2013: For each of these categories Executive, Management, Salaries Professionals and Unionized - Average Base Salary, Average Variable Pay, Average Total Cash Compensation. Please include FTEs in the schedule in each category.

Response:

Please see the response at Exhibit J.D-9-3-1.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 4 & Exhibit D5, Tab 1, Schedule 1, Updated & Exhibit D6, Tab 1, Schedule 1

a) Please provide a table that shows the actual corporate property taxes paid in 2007 through 2011, along with the forecasts for 2012 and 2013. Please also show the property taxes allocated in each year to the unregulated business and the net property tax amount allocated to the regulated portion of Union Gas. Please do not include any capital taxes in the 2007 through 2010 figures.

b) How much of the reduction in property and capital taxes between 2010 and 2011 shown in Exhibit D5, Tab 1, Schedule 1, Updated was due to the elimination of the capital tax?

c) If the response to part (b) above is less than $4.431 million, please explain the reduction in property taxes between 2010 and 2011.

d) What is the reduction in property and capital taxes between the Board Approved figure and the actual 2010 figure shown in Exhibit D6, Tab 1, Schedule 1 that is due solely to the phase out of the capital tax?

e) What measure of inflation has Union used to adjust the property taxes? Please provide the actual inflation rate based on this measure for each of 2007 through 2011 and the forecasts used for 2012 and 2013.

Response:

a)

$Millions

Line No.	Tax Year	Property Tax Expensed	Regulated Portion	Unregulated Portion
1	2007	58.122	57.400	0.722
2	2008	59.443	58.704	0.739
3	2009	61.295	59.996	1.299
4	2010	61.518	60.199	1.319
5	2011	61.539	60.215	1.324
	Forecast			
6	2012	62.991	61.595	1.396
7	2013	64.114	62.694	1.420

b) The elimination of the capital tax resulted in a $4.447 million reduction to property and capital taxes from 2010 to 2011.

c) The response to (b) accounted for more than the $4.431 million variance.

d) The $2.578 million net reduction to property and capital taxes is composed of a $3.410 million reduction due to the phase out of capital tax, partially offset by an increase in property taxes.

e) The measure of inflation used by Union is not based on a published index. Union uses the 5-year average of the actual year over year change (rounded to the nearest half percent) of the amount of tax Union is charged on its pipelines (net of additions). The annual change and 5-year average used in the forecast are provided in the table below.

Line No.	Tax Year	Annual Change	5-Year Average
1	2007	3.6%	
2	2008	(0.2%)	
3	2009	0.9	
4	2010	(0.2%)	
5	2011	(1.1%)	0.5%
	Forecast		
6	2012	0.5%	
7	2013	0.5%	

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit D1, Tab 4, Page 3

Union indicates that it is including an additional $0.16 million in property tax expenses due to an Enbridge related Assessment Review Board (ARB) ruling to re-classify odourant stations from commercial to industrial. Please confirm that this ARB decision is a final and non-appealable form.

Response:

The ARB decision is final authority on questions of fact. Section 43.1 of the Assessment Act allows an appeal from the decision of the ARB to Divisional Court, but only if leave is granted by the Court, and only on a question of law.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4/Pg.1; D3/Tab 5/Schedule 1

On Line 1 “Tax on Income” of Table 2 “2013 Income Tax Expense” on Exhibit D1 Tab 4 page 1, Union has forecasted an amount of $23.6 million for income tax. However, on Line 12 “Income taxes” of Union’s calculation of utility’s income taxes for 2013 on Exhibit D3 Tab 5 Schedule 1, the income tax is calculated as $21,743,000. Please confirm which figure is the forecast income tax for 2013 and please update the respective evidence accordingly.

Response:

The correct figure is contained in Exhibit D3 Tab 5 Schedule 1 ($21,743,000). Exhibit D1 Tab 4 page 1 was not updated to reflect the revised 2013 forecast.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4; Exh D5/Tab 5/Schedule 1; Exh D6/Tab 5/Schedule 1

Union filed the calculation of 2010 utility income tax in schedule 1 of Exhibit D6 Tab 5. Please provide the complete sets of tax returns, tax assessments, and reassessments if applicable for the years 2010.

Response:

Union declines to provide its 2010 tax returns, tax assessments and reassessments. Union’s tax filings pertain to its combined utility/non-utility operations and are filed in confidence with the Canadian Revenue Agency.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4

It appears that Union did not provide the calculations for the Capital Cost Allowance ("CCA") for the years 2010 to 2013.

a) Please provide the Schedule 8 CCA in Union's income tax returns for 2010.

b) Please provide the CCA calculations for the years 2011, 2012 and 2013. Please provide the tax act references for the CCA classes and CCA rates for the capital asset additions in 2011, 2012 and 2013.

c) Please confirm that the capital assets showing the CCA calculation schedules to be provided by Union are 100% related to Union's regulated business. Please provide the explanation and the supporting documents if otherwise.

Response:

a) Please see the response at Exhibit J.D-11-1-2.

b) CCA calculations for 2011, 2012 and 2013 were included as part of Union's pre-filed evidence. Please refer to Exhibit D3, Tab 5, Schedule 2; Exhibit D4, Tab, Schedule 2; and, Exhibit D5, Tab 5, Schedule 2.

The tax act references are included in the table below:

Class	Tax Act Reference
1 – 4%	Regulation 1100(1)(a)(i)
1 – 6%	Regulation 1100(1)(a.2)
2	Regulation 1100(1)(a)(ii)
3	Regulation 1100(1)(a)(iii)
6	Regulation 1100(1)(a)(vi)
7	Regulation 1100(1)(a)(vii)
8	Regulation 1100(1)(a)(viii)
10	Regulation 1100(1)(a)(x)
12	Regulation 1100(1)(a)(xii)
13	Regulation 1100(1)(b)
17	Regulation 1100(1)(a)(xiv)
38	Regulation 1100(1)(zd)
41	Regulation 1100(1)(a)(xxvii)
45	Regulation 1100(1)(a)(xxxi)
49	Regulation 1100(1)(a)(xxxv)
50	Regulation 1100(1)(a)(xxxvi)
51	Regulation 1100(1)(a)(xxxvii)
52	Regulation 1100(1)(a)(xxxviii)

c) The CCA schedules provided are 100% related to Union’s regulated business.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4/ Pg.2

Union described its forecast methodology for its income tax in Exhibit D1, Tab 4, page 2.

Please disclose any significant changes that Union has incorporated into its forecast 2013 income tax calculation as compared to the prior years. The changes should include but not limited to the impact from the transitioning to USGAAP, the CCA class changes for Union's existing capital assets, the CCA rate changes for Union's existing capital assets and the CCA class and rates chosen for the capital assets additions in 2013

Response:

There have been no significant changes made to Union's 2013 tax forecast as compared to prior years. The transition to US GAAP does not impact the CCA classification or rates for existing assets or for capital asset additions in 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4/ Pg.2

Union has indicated that in the E.B.R.O. 499 ADR Settlement Agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union's cost of service in future years.

Union provided the deferral tax draw down schedule in Appendix A of Exhibit D1/ Tab 4.

a) Please provide the original deferred tax draw down schedule evidence provided and agreed in E.B.R.O 499 Settlement Agreement.

b) If the draw down schedule provided in this rate application differs from the one provided in E.B.R.O 499, please provide the explanation and reconciliation with the original schedule.

Response:

a) Please see Attachment 1.

b) The deferred tax draw down schedule agreed to in EBRO 499 included deferred taxes associated with Union's regulated and unregulated assets. Union determined that approximately 10.3% of the assets that gave rise to the deferred tax balance at December 31, 1996 were associated with Union's unregulated business. The deferred tax draw down schedule provided at Exhibit D1 Tab 4 Appendix A reflects the draw down associated with Union's regulated business only.

A reconciliation has been provided below:

Reconciliation of Deferred Tax Drawdown
($000's)

Line No.	Year	Total Company (EBRO 499)	Regulated (D1,T4, Appendix A)	Unregulated
1	2010	(19,002)	(17,041)	(1,961)
2	2011	(17,606)	(15,790)	(1,816)
3	2012	(16,542)	(14,835)	(1,707)
4	2013	(16,914)	(15,169)	(1,745)
5	2014	(15,014)	(13,465)	(1,650)
6	2015	(15,115)	(13,556)	(1,559)
7	2016	(14,608)	(13,100)	(1,508)
8	2017	(14,653)	(13,141)	(1,512)
9	2018	(12,076)	(10,832)	(1,244)

Appendix A

Unio[illegible]s Limited
Comparison of Accounting Depreciation to Tax CCA (excluding rental business)
1997 - 2018

Fiscal Year	Accounting Depreciation	LTD Issue Cost Amortized	Total Accounting	CCA	CEC	Tax LTD	EXP & DEV	Total Tax	Difference	Tax Amount	Drawdown Utilized	Deferred Tax
1996												(318,046)
1997	(98,535)	(820)	(99,355)	104,983	619	1,165	265	107,031	7,676	3,339	-	(318,046)
1998	(96,264)	(780)	(97,044)	87,233	575	647	222	88,678	(8,366)	(3,914)	-	(318,046)
1999	(96,263)	(757)	(97,020)	75,854	535	322	189	76,901	(20,119)	(9,412)	(9,412)	(308,634)
2000	(96,263)	(757)	(97,020)	66,784	498	73	162	67,517	(29,503)	(13,802)	(13,802)	(294,833)
2001	(87,006)	(683)	(87,689)	59,448	463	-	141	60,051	(27,638)	(12,929)	(12,929)	(281,904)
2002	(83,942)	(681)	(84,623)	53,453	430	-	123	54,006	(30,617)	(14,323)	(14,323)	(267,581)
2003	(83,802)	(681)	(84,483)	48,507	400	-	108	49,015	(35,468)	(16,592)	(16,592)	(250,989)
2004	(83,490)	(681)	(84,171)	44,357	372	-	95	44,824	(39,346)	(18,406)	(18,406)	(232,583)
2005	(81,067)	(511)	(81,578)	40,836	346	-	84	41,267	(40,311)	(18,857)	(18,857)	(213,726)
2006	(79,748)	(507)	(80,255)	37,816	322	-	75	38,213	(42,042)	(19,667)	(19,667)	(194,059)
2007	(70,498)	(472)	(70,970)	35,193	299	-	67	35,559	(35,411)	(16,565)	(16,565)	(177,493)
2008	(70,311)	(372)	(70,683)	32,886	278	-	60	33,224	(37,459)	(17,523)	(17,523)	(159,970)
2009	(70,198)	(370)	(70,568)	30,838	259	-	53	31,151	(39,417)	(18,439)	(18,439)	(141,531)
2010	(69,543)	(370)	(69,913)	29,004	241	-	48	29,293	(40,620)	(19,002)	(19,002)	(122,529)
2011	(65,209)	(41)	(65,250)	27,347	224	-	43	27,614	(37,636)	(17,606)	(17,606)	(104,923)
2012	(61,446)	-	(61,446)	25,838	208	-	39	26,085	(35,362)	(16,542)	(16,542)	(88,380)
2013	(60,841)	-	(60,841)	24,455	194	-	35	24,683	(36,157)	(16,914)	(16,914)	(71,466)
2014	(55,485)	-	(55,485)	23,180	180	-	31	23,391	(32,094)	(15,014)	(15,014)	(56,452)
2015	(54,505)	-	(54,505)	21,998	168	-	28	22,194	(32,311)	(15,115)	(15,115)	(41,337)
2016	(52,306)	-	(52,306)	20,899	156	-	25	21,080	(31,226)	(14,608)	(14,608)	(26,729)
2017	(51,363)	-	(51,363)	19,872	145	-	23	20,040	(31,323)	(14,653)	(14,653)	(12,076)
2018	(47,954)	-	(47,954)	18,910	135	-	20	19,065	(28,889)	(13,514)	(12,076)	-

Notes:

1. All calculations use 1996 actual values as the base year for following years' calculations.
2. Accounting Depreciation calculated for asset groups using 1996 depreciation rates on a straight line basis.
3. LTD = Long Term Debt issue costs. Costs associated with debt issues are amortized over term of debt for accounting purposes and over 5 years for tax purposes.
4. CCA = Capital Cost Allowance and represents the amount of "depreciation" allowed for tax purposes. Calculated using current CCA rates on a declining balance basis.
5. CEC = Cumulative Eligible Capital and represents "depreciation" of intangible assets. Calculated on a declining balance basis using current rate.
6. EXP. & DEV. represents cost of exploration and development depreciated for tax purposes on a declining balance basis.
7. Difference column represents total accounting write offs less total write offs for tax purposes.
8. Tax Amount is the difference column times the average tax rate (46.78%) in the years of accumulating deferred taxes.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D1/Tab 4/ Appendix A

Union provided the deferral tax draw down schedule for the years 2010 to 2018 in Appendix A of Exhibit D1/ Tab 4. Union also provided a similar schedule in its last cost of service rate application EB-2005-0520.

a) Please provide the deferred tax draw down schedule evidence in Union's last CoS rate application EB-2005-0520.

b) Please reformat the deferred tax draw down schedule in this rate application based on the format of the deferred tax draw down schedule in Union's last CoS rate application EB-2005-0520.

c) If the draw down schedule provided in this rate application differs from the one provided in EB-2005-0520, please explain the differences and perform necessary reconciliation.

Response:

a) Please see Attachment 1.

b) Please see Attachment 2.

c) As described in Union's response at Exhibit J.D-11-1-5, Exhibit D1 Tab 4 Appendix A reflects the drawdown associated with the regulated business whereas, the drawdown schedule provided in EB-2005-0520 included the drawdown associated with Union's regulated and unregulated business.

UNION GAS LIMITED
Comparison of Accounting Expenses To Deductions for Tax
2004-2018

Fiscal Year	Accounting Depreciation	LTD Issue Cost Amortized	Total Accounting	CCA	CEC	EXP & DEV	Total Tax	Difference	Tax Amount	Drawdown Utilized	Deferred Tax
2003											(250,989)
2004	(83,490)	(681)	(84,171)	44,357	372	95	44,824	(39,347)	(18,406)	(18,406)	(232,583)
2005	(81,067)	(511)	(81,578)	40,836	346	84	41,266	(40,312)	(18,857)	(18,857)	(213,726)
2006	(79,748)	(507)	(80,255)	37,816	322	75	38,213	(42,042)	(19,667)	(19,667)	(194,059)
2007	(70,498)	(472)	(70,970)	35,193	299	67	35,559	(35,411)	(16,565)	(16,565)	(177,494)
2008	(70,311)	(372)	(70,683)	32,886	278	60	33,224	(37,459)	(17,523)	(17,523)	(159,971)
2009	(70,198)	(370)	(70,568)	30,838	259	53	31,150	(39,418)	(18,439)	(18,439)	(141,532)
2010	(69,543)	(370)	(69,913)	29,004	241	48	29,293	(40,620)	(19,002)	(19,002)	(122,530)
2011	(65,209)	(41)	(65,250)	27,347	224	43	27,614	(37,636)	(17,606)	(17,606)	(104,924)
2012	(61,446)	-	(61,446)	25,838	208	39	26,085	(35,361)	(16,542)	(16,542)	(88,382)
2013	(60,841)	-	(60,841)	24,455	194	35	24,684	(36,157)	(16,914)	(16,914)	(71,468)
2014	(55,485)	-	(55,485)	23,180	180	31	23,391	(32,094)	(15,014)	(15,014)	(56,454)
2015	(54,505)	-	(54,505)	21,998	168	28	22,194	(32,311)	(15,115)	(15,115)	(41,339)
2016	(52,306)	-	(52,306)	20,899	156	25	21,080	(31,226)	(14,608)	(14,608)	(26,731)
2017	(51,363)	-	(51,363)	19,872	145	23	20,040	(31,323)	(14,653)	(14,653)	(12,078)
2018	(47,954)	-	(47,954)	18,910	135	20	19,065	(28,889)	(13,514)	(12,078)	-

Notes:
1. LTD = Long Term Debt issue costs that are amortized over term of debt for accounting purposes and over 5 years for tax purposes.
2. CCA = Capital Cost Allowance and represents the amount of "depreciation" allowed for tax purposes.
3. CEC = Cumulative Eligible Capital and represents "depreciation" of intangible assets allowed for tax purposes.
4. EXP & DEV represents cost of exploration and development "depreciated" for tax purposes.
5. Difference column represents total accounting expenses less total deductions allowed for tax purposes.
6. Tax Amount is the difference column times the average tax rate (46.78%) in the years of accumulating deferred taxes.

UNION GAS LIMITED
Comparison of Accounting Expenses To Deductions for Tax
2010-2018

Fiscal Year	Accounting Depreciation	LTD Issue Costs Amortized	Total Accounting	CCA	CEC	Exp & Dev	Total Tax	Difference (1)	Tax Amount (2)	Drawdown Utilized	Deferred Tax
2009											(126,929)
2010	(62,368)	(332)	(62,700)	26,011	216	43	26,271	(36,429)	(17,041)	(17,041)	(109,888)
2011	(58,518)		(58,518)	24,525	201	39	24,765	(33,753)	(15,790)	(15,790)	(94,098)
2012	(55,106)		(55,106)	23,172	187	35	23,394	(31,713)	(14,835)	(14,835)	(79,263)
2013	(54,564)		(54,564)	21,932	174	31	22,137	(32,426)	(15,169)	(15,169)	(64,094)
2014	(49,760)		(49,760)	20,788	161	28	20,978	(28,783)	(13,465)	(13,465)	(50,629)
2015	(48,881)		(48,881)	19,728	151	25	19,904	(28,977)	(13,556)	(13,556)	(37,074)
2016	(46,909)		(46,909)	18,743	140	22	18,905	(28,004)	(13,100)	(13,100)	(23,973)
2017	(46,064)		(46,064)	17,822	130	21	17,972	(28,091)	(13,141)	(13,141)	(10,832)
2018	(43,006)		(43,006)	16,959	121	18	17,098	(25,908)	(12,120)	(10,832)	(0)

Notes:
1. Difference column represents total accounting expenses less total deductions allowed for tax purposes.
2. Tax Amount is the difference column times the average tax rate (46.78%) in the years of accumulating deferred taxes.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D3/Tab 5/Schedule 1

Union provided the calculation for the 2013 utility income tax in schedule 1 of Exhibit D3/Tab 5. Please provide the breakdown, the calculation for the breakdown and supporting documents for the figures noted below:

- Utility Permanent Difference: 4,693,000

- Other: (32,921,000)

Response:

Details underpinning "Utility Permanent Differences" and"Other" have been provided in the tables below:

Utility Permanent Differences:

($000's)	
Stock based compensation	$ 3,272
Non-deductible meals and entertainment	1,117
Non-deductible depreciation	292
Other	12
Total	$ 4,693

Other:

($000's)	
Eligible capital expenditures	$ (841)
Vehicle depreciation capitalized	(2,265)
Interest during construction	(2,282)
Items capitalized for accounting purposes	(27,496)
Other	(37)
Total	$ (32,921)

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh D3/Tab 5/Schedule 1

Union provided the calculation for the 2013 utility income tax in schedule 1 of Exhibit D3/Tab 5. The figure on line 9 "Gas Cost Deferral and Other (current)" and the figure on line 13 "Deferred tax on Gas Cost Deferral" on the schedule are both zero. Please explain why Union has forecasted these two figures to be nil in 2013?

Response:

The "Gas cost deferral and Other (current)" line of Exhibit D3 Tab 5 Schedule 1 Line 9 represents the change in deferral account balances. Line 13 of the same schedule represents the tax effect associated with Line 9. Union has forecasted no change in the deferral account balances and, as a result, the number is nil. The associated tax effect (Line 13) is therefore, also nil.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 5, Schedule 1, Updated

a) Please explain the Utility Permanent Differences figure of 4,693 and also explain why it has increased from the figures shown for 2012 and 2011 in the corresponding schedules in Tab 5 of Exhibits D4 and D5.

b) Please explain what is included in the Other figure of (32,921) and also explain why it has decreased in magnitude from the figures shown for 2012 and 2011.

c) Has Union included any tax credits associated with the Co-Operative Education Tax Credit ("CETC"), the provincial Apprenticeship Training Tax Credit ("ATTC")or the federal Apprenticeship Job Creation Tax Credit ("AJCTC") in the calculation of its income taxes? If not, why not? If yes, please provide the calculations of each of the tax credits, including the number of eligible employees and the credit per employee and indicate where in Schedule 1 this deduction is included.

d) Please provide the number of positions eligible for each of the CETC, ATTC and AJCTC credits in each of 2010 and 2011 and the forecast number of eligible positions for 2012 and 2013.

Response:

a) The Utility Permanent Differences includes those costs that are expensed for accounting purposes but are not deductible (on a permanent basis) for tax purposes. Included in the permanent differences are costs such as the non-deductible portion (50%) of meals and entertainment as well as stock-based compensation costs. The increase in 2013 over 2012 and 2011 is driven by higher anticipated stock compensation costs.

b) The "Other" Utility Timing Differences includes costs that have been capitalized for accounting purposes but are deductible for tax purposes. The "Other" category consists primarily of capitalized overheads, capitalized interest and asset abandonment costs. The decrease is primarily driven by a decrease in deductible capitalized overheads and lower abandonment costs.

c) Union has not included any credits associated with these programs in the calculation of income taxes for two primary reasons. First, the forecast is not prepared at a detailed enough level such that these particular types of roles can be specifically identified. Second, the credits have, historically, been immaterial (less than $0.040 million per year).

d) The number of positions eligible for the CETC credit are 13 and 11 for 2010 and 2011 respectively. Union does not have any positions that qualify for ATTC or AJTC credits. As stated in the response to c) above, Union has not included a forecast of credits in 2012 or 2013.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association (“LPMA”)

Ref: Exhibit D3, Tab 5, Schedule 1, Updated

Has Union calculated the maximum CCA deduction available in the 2013 test year?

Response:

The CCA deduction at line 5 of Exhibit D3, Tab 5, Schedule 1 is the maximum deduction available.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 5, Schedule 2

Please update the CCA calculation for 2013 based on the actual CCA calculations for 2011 and any changes made in the forecast of capital expenditures for 2012 and 2013 in the update.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Calculation of Capital Consumption Allowance (CCA)
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)		Average CCA Balance (a)	Rate (%) (b)		Provision (c)
	Class					
1	1	Buildings, structures and improvements, services, meters, mains	$ 1,259,975	4.0%		$ 50,399
2	1	Non-residential building acquired after March 19, 2007	78,600	6.0%		4,716
3	2	Mains acquired before 1988	147,500	6.0%		8,850
4	3	Buildings acquired before 1988	4,280	5.0%		214
5	6	Other buildings	170	10.0%		17
6	7	Compression equipment acquired after February 22, 2005	160,493	15.0%		24,074
7	8	Compression assets, office furniture, equipment	82,805	20.0%		16,561
8	10	Transportation, computer equipment	21,280	30.0%		6,384
9	12	Computer software, small tools	7,701	100.0%		7,701
10	13	Leasehold improvements		N/A	(1)	113
11	17	Roads, sidewalk, parking lot or storage areas	950	8.0%		76
12	38	Heavy work equipment	5,927	30.0%		1,778
13	41	Storage assets	7,568	25.0%		1,892
14	45	Computer hardware acquired after March 22, 2004 and before March 19, 2	247	45.0%		111
15	49	Transmission pipelines acquired after February 22, 2005	202,738	8.0%		16,219
16	50	Computer hardware acquired after March 18, 2007	22,967	55.0%		12,632
17	51	Distribution pipelines acquired after March 18, 2007	571,233	6.0%		34,274
18	52	Computer hardware acquired after January 27, 2009 and before February 2	0	100.0%		0
19	Total		$ 2,574,434			$ 186,011

Notes:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 5, Schedule 1, Updated

What is the impact on income taxes and on the revenue requirement of the March 27, 2012 Ontario budget that cancels further reductions in the provincial corporate income tax rate and leaves it at 11.50%?

Response:

Leaving the income tax rate at 11.50% increases the revenue deficiency for 2013 by $2.121 million.

Line No.	Particulars ($)		Reference
1	Income taxes	853,000	(Exhibit D3, Tab 5, Schedule 1, line 11 x 1%)
2	Provision for income taxes on deficiency	706,000	(Exhibit F3, Tab 1, Schedule 1, line 7, x 1%)
3		1,559,000	
4	Grossed up for tax (line 3/ (1 – 26.5%)	2,121,000	

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, page 9, Updated

a) Does Union's proposal with respect to updating bad debt as part of the QRAM process, similar to unaccounted for gas, Company used gas, and gas inventory for sale, result in less risk for Union with respect to deviations from forecast for bad debt?

b) Please explain why Union should be able to pass this added risk onto ratepayers.

Response:

a) Union's proposal with respect to updating bad debt as part of the QRAM process, similar to unaccounted for gas, Company used gas, and gas inventory for sale would reduce the volatility risk associated with the component related to cost of gas. The cost of gas is outside the Company's control. However, Union would still be subject to the remaining components of the bad debt expense and the ultimate collection of the accounts, including the number of doubtful accounts.

b) Gas commodity related costs are typically passed through to consumers and the cost of gas component in bad debt is another item that should be treated consistently. Union is proposing to further harmonize its QRAM with Enbridge and include bad debt as part of the QRAM process.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 2, page 9, Updated

a) Please provide the cost of gas component of the bad debt expense for each year 2007 through 2011.

b) Please provide the cost of gas component of the bad debt expense that was included in the Board-approved 2007 O&M costs.

c) Please provide the cost of gas forecast used in the 2007 Board-approved costs.

d) Based on the above responses, please show the amounts that would have been accounted for under Union's current proposal to update the bad debt expense as part of the QRAM process had it been in place from the beginning of 2007.

Response:

a) and b) Please see Attachment 1.

c) The cost of gas forecast used in the 2007 Board-approved costs was the July 1, 2005 WACOG of \$ 355.473 per 10^3m^3.

d) Please see Attachment 2.

UNION GAS LIMITED
Cost of Gas Component of the Bad Debt Expense

Line No.	Particulars ($ millions)	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Cost of Gas	1,135.83	1,154.20	1,169.45	1,023.22	795.55	755.94	721.23	697.84
2	GST on Cost of Gas	68.15	69.25	58.47	51.16	63.40	98.27	93.76	90.72
3		1,203.97	1,223.46	1,227.92	1,074.38	858.95	854.21	814.99	788.56
4	Write Off Ratio - %	0.41	0.30	0.30	0.32	0.32	0.25 [1]	0.31	0.31
5	Cost of Gas Component of Bad Debt	4.94	3.67	3.68	3.44	2.75	2.14	2.53	2.44

Notes: 1 - Corrected

Union Gas Limited
Impact of cost of gas changes
on bad debt expense quarterly

Line No.	Particulars		2007 Jan (a)	Apr (b)	Jul (c)	Oct (d)	2008 Jan (e)	Apr (f)	Jul (g)	Oct (h)	2009 Jan (i)	Apr (j)	Jul (k)
	North - Alberta Border												
1	Proposed	$/ 10*3 m*3	298.49	310.97	314.38	278.62	256.75	288.81	359.72	319.36	286.85	223.41	195.15
2	Previously approved	$/ 10*3 m*3	301.62	298.49	310.97	314.38	278.62	256.75	288.81	359.72	319.36	286.85	223.41
3	Change	$/ 10*3 m*3	(3.13)	12.48	3.41	(35.76)	(21.87)	32.06	70.91	(40.36)	(32.51)	(63.44)	(28.26)
4	Sales volume	10*3 m*3	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293
5	Change in revenue	$000's	(1,920)	7,654	2,091	(21,931)	(13,413)	19,662	43,489	(24,753)	(19,938)	(38,907)	(17,332)
6	Bad debt ratio	%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%
7	Impact on bad debt	$000's	(8)	31	9	(90)	(55)	81	178	(101)	(82)	(160)	(71)
	South - WACOG												
8	Proposed	$/ 10*3 m*3	351.05	363.58	368.15	330.77	307.44	343.06	427.82	381.63	350.58	277.11	247.68
9	Previously approved	$/ 10*3 m*3	355.47	351.05	363.58	368.15	330.77	307.44	343.06	427.82	381.63	350.58	277.11
10	Change	$/ 10*3 m*3	(4.42)	12.53	4.57	(37.38)	(23.33)	35.62	84.76	(46.19)	(31.05)	(73.47)	(29.44)
11	Sales volume	10*3 m*3	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002
12	Change in revenue	$000's	(9,941)	28,180	10,273	(84,072)	(52,471)	80,114	190,621	(103,877)	(69,823)	(165,227)	(66,206)
13	Bad debt ratio	%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%
14	Impact on bad debt	$000's	(41)	116	42	(345)	(215)	328	782	(426)	(286)	(677)	(271)
15	Total impact on bad debt	$000's	(49)	147	51	(435)	(270)	409	960	(527)	(368)	(837)	(343)

Line No.	Particulars		Oct (l)	2010 Jan (m)	Apr (n)	Jul (o)	Oct (p)	2011 Jan (q)	Apr (r)	Jul (s)	Oct (t)	2012 Jan (u)	Apr (v)
	North - Alberta Border												
1	Proposed	$/ 10*3 m*3	189.06	189.63	200.31	164.62	147.90	136.85	134.01	142.02	131.18	115.70	89.22
2	Previously approved	$/ 10*3 m*3	195.15	189.06	189.63	200.31	164.62	147.90	136.85	134.01	142.02	131.18	115.70
3	Change	$/ 10*3 m*3	(6.09)	0.57	10.68	(35.69)	(16.72)	(11.05)	(2.84)	8.01	(10.84)	(15.48)	(26.49)
4	Sales volume	10*3 m*3	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293	613,293
5	Change in revenue	$000's	(3,735)	350	6,550	(21,888)	(10,254)	(6,777)	(1,742)	4,912	(6,648)	(9,491)	(16,244)
6	Bad debt ratio	%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%
7	Impact on bad debt	$000's	(15)	1	27	(90)	(42)	(28)	(7)	20	(27)	(39)	(67)
	South - WACOG												
8	Proposed	$/ 10*3 m*3	241.29	257.16	267.66	230.95	213.93	202.61	222.35	230.80	219.25	203.32	176.43
9	Previously approved	$/ 10*3 m*3	247.68	241.29	257.16	267.66	230.95	213.93	202.61	222.35	230.80	219.25	203.32
10	Change	$/ 10*3 m*3	(6.39)	15.87	10.50	(36.71)	(17.02)	(11.32)	19.74	8.46	(11.55)	(15.93)	(26.89)
11	Sales volume	10*3 m*3	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002	2,249,002
12	Change in revenue	$000's	(14,364)	35,696	23,606	(82,565)	(38,269)	(25,456)	44,391	19,018	(25,980)	(35,827)	(60,480)
13	Bad debt ratio	%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%
14	Impact on bad debt	$000's	(59)	146	97	(339)	(157)	(104)	182	78	(107)	(147)	(248)
15	Total impact on bad debt	$000's	(74)	148	124	(428)	(199)	(132)	175	98	(134)	(186)	(315)

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab 2, Page 9

To manage the impact of changes in the cost of gas on bad debt expense, Union is proposing to update the bad debt expense as part of the Quarterly Rate Adjustment Mechanism similar to unaccounted for gas, Company used gas, and gas inventory for resale. The bad debt expense in the 2012 and 2013 forecast is at historic lows as a result of the current cost of gas. This forecast is based on the January 1, 2011 weighted average cost of gas ("WACOG") of $202.610 per 10 3 m3. An increase of 10% in WACOG will increase Union's bad debt expense approximately $0.4 million.

a) Provide the cost of gas component of the bad debt expense for each year 2007 through 2011and forecast 2012/2013.

b) Does Union have a Regression Equation for forecasting Bad Debt Expense? If so, provide a Summary and historical results. If not, identify the Factors that Drive Bad Debt Expense.

c) How much is explained by Gas Price Changes and by these other factors? Please provide sensitivities.

d) If the 2013 forecast is flat why is it necessary to adjust bad debt quarterly for gas prices?

e) Based on the above responses, please show the amounts that would have been accounted for under Union's current proposal from 2007-present.

Response:

a) Please see the response at Exhibit J.D-12-2-2 a).

b) No, Union does not have a Regression Equation for forecasting Bad Debt Expense. The factors that drive bad debt expense are total revenue and historic write offs.

c) A 10% increase in WACOG will result in a $0.4 million increase in bad debt, as per Exhibit D1, Tab 2, p.9.

   A 10% increase in total revenue will result in a $0.5 million increase in bad debt.

A decrease to the bad debt write-off ratio from 0.3% to 0.2% will result in a $2.1 million decrease in bad debt.

d) The QRAM process is not intended to address the effects of quarterly variances in bad debt resulting from changing gas prices but is instead intended to address the long-term variances in the gas prices.

e) Please see the response at Exhibit J.D-12-2-2 d).

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 2, page 9

Please explain why Union is proposing to update the bad debt expense as part of the QRAM process. Why is this expense unlike Union's other O&M expenses?

Response:

Please see the response at Exhibit J.D-12-2-1.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Association of Physical Plant Administrators ("OAPPA")

Reference: Exhibit 01, Tab 2, page 9

Using the April 1, 2012 QRAM filing (EB-2012-0070) as the base, please show how the debt expense would be updated as part of the QRAM, including how the unit rate changes by rate class would be derived.

Response:

For the calculation of the bad debt expense for the April 1, 2012 QRAM, please see the response at Exhibit J.D-12-2-2 d).

Once the update to the bad debt expense has been calculated, Union will determine the unit rate change to the gas supply administration fee by dividing the change in bad debt expense by the 2007 Board-approved sales volumes. The gas supply administration fee is included in the gas commodity and fuel rate for sales service customers. The calculation of the rate change between the January 1, 2012 QRAM and the April 1, 2012 QRAM is shown in Attachment 1.

Union Gas Limited
Calculation of April 1, 2012 QRAM Unit Rate Change in Gas Supply Admin Fee related to Bad Debt
Jan - Apr 2012 QRAM

Line No.	Particulars	
1	Bad Debt Expense Update ($000's)	(315)
2	2007 Board-approved Sales Volume (10^3m^3)	2,976,764
3	Unit Rate Change (cents/m^3) (line 1 / line 2)	(0.0106)
4	January 1, 2012 QRAM Gas Supply Administration Fee (cents/m^3)	0.3138
5	Unit Rate Change (cents/m^3) (line 3)	(0.0106)
6	April 1, 2012 QRAM Gas Supply Administration Fee (cents/m^3) (line 4 + line 5)	0.3032

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 3, Schedule 2, Updated & Exhibit D3, Tab 2, Updated

a) Please show where the test year costs associated with unaccounted for gas, company used gas and gas inventory for resale are shown in Exhibit D3, Tab 3, Schedule 2, Updated, Exhibit D3, Tab 2, Updated and/or whatever other schedule where these cost are reflected. Please identify the line item and indicate if the line item is only for the specified cost or whether other costs are included in a line item that contains one or more of the requested costs.

b) Please provide the 2007 through 2011 actual costs and the forecasts for 2012 and 2013 for each of the unaccounted for gas, company used gas and gas inventory for resale.

c) Are the adjustments for each of these three costs that are done as part of the QRAM process based on variances from the volume forecast only, variance from the cost of gas forecast only, or based on the variances from both the volume and cost of gas forecasts? Please provide an example for company used gas of an adjustment that has been made in a recent QRAM filing.

Response:

a)

Line No.	Cost	Location	Includes other costs?
1	Unaccounted for Gas	Exhibit D3, Tab 2, Schedule 2, Line 12, Updated	No
2	Company Used Gas	Exhibit D1, SS2, Line 9 Exhibit D3, T3, S2, Page 1, Line 9, Updated	No
3	Gas Inventory for Resale	Exhibit B1, SS1, Line 5, Updated Exhibit B3, Tab 1, Schedule 1, Line 5, Updated	Yes – also includes line pack gas

b)

Line No.	Particulars ($000's)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	UFG	70,414	56,242	55,999	13,686	8,041	15,470	14,234
2	Company Used Gas	3,167	3,548	3,373	2,451	2,401	2,473	2,502
3	Gas Inventory for Resale	143,263	115,503	116,075	160,590	143,743	144,727	147,539

c) Adjustments done as part of the QRAM process relate to price variances only. Please see Attachment 1 for an example of the QRAM adjustment for company used gas.

UNION GAS LIMITED
Derivation of Unit Rate Changes related to Gas Costs in Distribution Rates
effective April 1, 2012

Line No.	Derivation of Amounts for Recovery			
	Change in Gas Cost:			
1	Ontario Landed Reference Price as per EB-2012-0070	($/$10^3m^3$)	176.430	
2	Ontario Landed Reference Price as per EB-2011-0382	($/$10^3m^3$)	203.322	
3	Change in Gas Cost (line 1 - line 2)	($/$10^3m^3$)	(26.891)	
4	Fuel and UFG volume: 2007 approved	(10^3m^3)	91,291	
5	Amount for Recovery - Fuel & UFG (line 3 x line 4)	($000's)	(2,453)	
6	Average Gas in Inventory: 2007 approved	(10^3m^3)	539,876	
7	Change in Gas Costs related to Inventory (line 3 x line 6)	($000's)	(14,518)	
8	Composite Rate of Return		5.45%	(1)
9	Amount for Recovery - Gas in Storage (line 7 x line 8)	($000's)	(791)	
10	Total Gas Cost Change to Distribution Rates (line 5 + line 9)	($000's)	(3,244)	

Derivation of Unit Rate Changes by Rate Class

Line No.	Rate Class	Fuel & Unaccounted for Gas: Cost Allocation (2) ($000's) (a)	Allocation Factor (%) (b)	Amount for Recovery ($000's) (c)	Gas in Storage Carrying Costs: Cost Allocation (3) ($000's) (d)	Allocation Factor (%) (e)	Amount for Recovery ($000's) (f)	Total Gas Cost Change to Distribution Rates ($000's) (g) = (c+f)		2012 Annual Distribution Volume (4) (10^3m^3) (h)	Unit Rate Change (5) (cents/m^3) (i) = (g/h)
11	M1	8,829	35.08%	(861)	58,368	54.74%	(433)	(1,294)		2,650,399	(0.0488)
12	M2	5,467	21.73%	(533)	14,786	13.87%	(110)	(643)		1,017,919	(0.0631)
13	M4	1,647	6.55%	(161)	3,398	3.19%	(25)	(186)		462,743	(0.0401)
14	M5 F/I	1,376	5.47%	(134)	2,759	2.59%	(20)	(155)		369,224	(0.0419)
15	M7 F/I	973	3.87%	(95)	2,168	2.03%	(16)	(111)		269,201	(0.0412)
16	M9	94	0.37%	(9)	471	0.44%	(3)	(13)		24,506	(0.0516)
17	M10	-	0.00%	-	6	0.01%	(0)	(0)		202	(0.0220)
18	T1 F/I	-	0.00%	-	-	0.00%	-	-	(5)		
19	T3	-	0.00%	-	-	0.00%	-	-	(5)		
20	M12	-	0.00%	-	-	0.00%	-	-	(5)		
21	M13	340	1.35%	(33)	-	0.00%	-	(33)	(5)		
22	M16	244	0.97%	(24)	-	0.00%	-	(24)	(5)		
23	C1	-	0.00%	-	-	0.00%	-	-	(5)		
24	Rate 01	3,555	14.13%	(347)	17,461	16.38%	(130)	(476)		863,695	(0.0551)
25	Rate 10	707	2.81%	(69)	5,589	5.24%	(41)	(110)		451,957	(0.0244)
26	Rate 20	132	0.52%	(13)	704	0.66%	(5)	(18)		519,357	(0.0035)
27	Rate 100	1,801	7.16%	(176)	913	0.86%	(7)	(182)		2,219,052	(0.0082)
28	Rate 25	-	0.00%	-	-	0.00%	-	-			
29	Rate 77	-	0.00%	-	-	0.00%	-	-			
30	Total	25,166	100.00%	(2,453)	106,624	100.00%	(791)	(3,244)			

Notes:
(1) Calculation of the Composite Return:

Common Equity (after tax)	36.00%	8.54%	3.07%
Gross-Up for tax (@ 31.19%)			1.39%
Common Equity (pre-tax)			4.46%
Short-Term Debt	64.00%	1.55%	0.99%
Composite Rate of Return			5.45%

(2) EB-2005-0520, Decision Cost Study, Operating Expenses, A. Cost of Gas & Production, Other Supplies - UFG, pages 13-16, and
EB-2005-0520, Decision Cost Study, Operating Expenses, C. Underground Storage & D. Transmission, Compressor Fuel, pages 13-16.
(3) EB-2005-0520, Storage Excluding Dehydrator Space, Working Capital, Gas in Storage, Pages 10-12.
(4) EB-2011-0025, Rate Order, Working Papers, Schedule 4, Column (r).
(5) Union supplied fuel (USF) rate changes for Rates T1, T3, M12, M13, M16 and C1 are based on approved 2011 fuel ratios and proposed Ontario Landed Reference Price.
Changes in Union-supplied fuel rates for Rate T1, T3, M12, M13, M16 and C1 are presented at Appendix A, Schedule "C", and Working Papers, Schedule 1, Page 6.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 2, Schedule 1, page 2, Updated & Exhibit D3, Tab 3, Schedule 2, page 1, Updated

What is the relationship, if any, between the Company Used Gas shown on page 1 of Exhibit D3, Tab 3, Schedule 2, Updated at line 9 for 2013 of 2,501 and the Company Use Adj. shown on line 7 of page 2 of Exhibit D3, Tab 2, Schedule 1, Updated of (1,960).

Response:

There is no relationship between these two line items.

"Company Used Gas" shown at Line 9 of Exhibit D3, Tab 3, Schedule 2, Page 1, Updated refers to the O&M expense for gas consumed to heat Union's office buildings, stations, line heaters, auxiliary generators, etc. It excludes costs for compressors and dehydration units.

"Company Use Adj." Shown at Line 7 of Exhibit D3, Tab 2, Schedule 1, Page 2 refers to compressor fuel offset by compressor fuel that is provided by customers.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 1, pages 7-8

a) Please update the gas supply plan to reflect transportation tolls and gas prices utilized in the development of the plan to those used to set the April 1, 2012 Quarterly Rate Adjustment Mechanism commodity price.

b) What is the impact on the gas supply plan if the direct purchase demand is updated to reflect the number of direct purchase customers as of January 1, 2012?

Response:

a) Please see Attachment 1.

b) There is currently no updated demand forecast available with direct purchase customers as of January 1, 2012 to update the gas supply plan.

The major items in the gas supply plan that would be impacted by an updated demand forecast with direct purchase customers as of January 1, 2012 would be:

- Storage allocations – the system sales service allocation of storage will increase as customers migrate from direct purchase back to system sales service and the opposite holds true when customers move from sales service to direct purchase. There would be an equal and offsetting change in the allocation to direct purchase customers;
- Balancing gas – the balancing gas requirement for direct purchase customers will increase or decrease due to the amount of migration to or away from direct purchase. The balancing gas available for use by system sales service customers will also change accordingly;
- Direct purchase DCQ's – will change as customers move away from or to the direct purchase service option;
- Upstream transportation – system sales service will be allocated more or less of the upstream transportation to fill as direct purchase DCQ's change. This assumes that customers returning to system return upstream pipeline transportation capacity upon their return. Many of these customers have turned back capacity so they return with no firm pipe or only a portion of firm pipe; and,
- System integrity space allows Union, as an integrated storage and transmission system operator, to support the integrity of the system as a whole and provide the provision of service to all customers. The gas plan will hold the same amount of

system integrity space regardless of the mix of system sales and direct purchase customers.

UNION GAS LIMITED
Gas Purchase Expense - Updated for April 2012 QRAM Transportation Tolls and Commodity Prices
Year Ending December 31, 2013

Line No.	Particulars	Volume (TJ)	Cost ($000's)	% of Total Volume
		(a)	(b)	(c)
Section A				
	Supply Transportation			
1	Western Canadian Firm	94,436	189,448	
2	U.S. Firm	43,416	18,778	
3	Adjustments	-	(105)	
4	Total Supply Transport	137,852	208,121	
	Supply Commodity			
5	Western Canadian Firm	75,939	189,410	49%
6	U.S. Firm	43,416	134,696	28%
7	Ontario Delivered Supplies	16,356	53,781	11%
8	Northern Bundled T-Service	18,497	-	12%
9	Adjustments	-	-	0%
10	Other	-	-	0%
11	Total Supply Commodity	154,208	377,888	100%
	Storage			
12	STS and Related Services		19,837	
13	Total Supply at Cost		605,846	
Section B				
	Storage Inventory Change			
14	LNG	-	-	
15	Other Company Owned	(1,596)	(7,444)	
16	3rd Party	-	-	
17	Total Gas (to) from Storage	(1,596)	(7,444)	
Section C				
18	Total Third Party Storage		426	
19	Total Section A, B, & C		598,827	

UNION GAS LIMITED
Gas Purchase Expense
Year Ending December 31, 2013

Line No.	Particulars	Volume (TJ)	Cost ($000's)
		(a)	(b)
	Gas Supply		
1	Total Supply at Cost	154,208	606,271
2	Deferred Costs		65,701
3	Total Gas Supply	154,208	671,972
4	Gas (to) from Storage	(1,596)	(7,444)
5	Winter Peaking Service		-
6	Other Transportation		972
7	Company Use Adj.		(1,703)
8	Linepack		(28)
9	Deferral Adjustment		(42,790)
10	UFG Adjustment		(6,664)
11	Accounting Adjustment		-
12	Total Cost of Gas	152,613	614,315
13	Less: Unregulated costs		(1,980)
14			612,335
15	Add: Costs related to short-term storage revenue		1,470
16	Total Utility Cost of Gas		613,805

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 1, page 1

The evidence indicates that the Trunkline/Panhandle contract has a term that expires October 31, 2012. What does Union plan to do to replace/extend this contract? Does the Niagara - Kirkwall contract noted on page 16 replace the Trunkline/Panhandle contract?

Response:

Union has renewed the existing Trunkline/Panhandle contracts and extended the term to October 31, 2017. The Niagara-Kirkwall contract will replace Dawn purchases from November 1, 2012 until November 30, 2015 when the Alliance-Vector contracts terminate. From that point forward, the Niagara-Kirkwall contract replaces a portion of the Alliance-Vector path.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 1, pages 15-16

Is Union able to move gas from the Sault Ste. Marie Delivery Area into other parts of the Union North supply area? Please explain.

Response:

Yes, Union is able to move gas from the Sault Ste. Marie Delivery Area (SSMDA) into other parts of the Union North supply area through the use of diversions or interruptible nominations on TCPL's Mainline.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 2, Schedule 5

Does Union propose to update the upstream transportation costs if new tolls are known before the conclusion of this rates proceeding?

Response:

The 2013 Rate Order will be based on upstream transportation tolls in effect at the time. Thereafter, the Quarterly Rate Adjustment Mechanism ("QRAM") process and the annual deferral account disposition process will account for any increases or decreases in upstream transportation tolls when they occur.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 1, page 2

The evidence states that in developing the gas supply plan Union models all upstream transportation capacity and storage assets to provide an integrated service across all delivery areas for bundled customers. Union uses SENDOUT to complete the gas supply plan and has been presented in previous rate applications including EB-2005-0520 (2007). The 5-year plan was completed in the Spring of 2011 and there are no material changes in the 2012-2016 plan from the plan filed in 2007. ICF has concluded that changing patterns in the North American natural gas market mean shippers are facing "changing economics for the acquisition of gas supply that will precipitate changes in their portfolio of gas transportation and storage assets under contract". (A2/T1/S4/p. 3) In light of ICF's conclusions, to what extent will Union be required to revise its gas supply planning process? Is the plan developed in 2011 still appropriate for 2013?

Response:

The changing patterns in the North American natural gas market will not impact Union's gas supply planning process.

The changing North American natural gas market will impact which transportation routes Union acquires as current upstream transportation contracts expire or additional upstream transport is required. As the market changes and new basin access and new transportation routes are developed, Union will evaluate these alternatives. Examples of the impact of the changing markets included in the current SENDOUT model are the path from MichCon to the SSMDA which was added effective November 1, 2011 and the TCPL Niagara to Kirkwall route forecasted to come on line November 1, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit D1, Tab 1, page 13

Union has elected not to extend the term of its Alliance contract beyond December 1, 2015 based on economic reasons. Please explain what arrangements will replace the contract and why the contract extension was not considered economic.

Response:

The arrangements that will replace the Alliance contract terminating December 1, 2015 have only been partially committed to date. Union bid into a TransCanada Open Season for 21,101 GJ/d (20,000 Dth/d) for Niagara to Kirkwall capacity which will replace a portion of the 80,000 Dth/d Alliance-Vector transportation path. The remainder of the replacement transportation path(s) for Alliance-Vector has not yet been determined. Please see the response at Exhibit J.D-14-2-2.

The contract extension was not considered economic compared to alternatives based primarily on the landed cost analysis performed at the time the renewal decision needed to be made. Other qualitative considerations included lack of liquidity at CREC and increasing flexibility in the portfolio for future contracting decisions.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pg 8

Preamble: Union discusses its Gas Supply Plan and the assumption that customers will remain with the service they received effective January 1, 2011. It is TransCanada's understanding that the level of system gas customers versus direct purchase customers has been changing quite dramatically over the past several years.

a) Please provide an updated Gas Supply Plan reflecting the latest level of system gas customers versus direct purchase customers.

b) Please provide the level of system gas customers versus direct purchase gas customers (annual volume in GJ's) for 2009, 2010, and 2011.

c) Does the level of system gas customers versus direct purchase customers impact the level of obligated deliveries at Parkway?

Response:

a) Please see the response at Exhibit J.D-14-2-1 b).

b) Please see the response at Exhibit J.D-16-2-1 b).

c) Union reviews the Parkway obligated deliveries as part of the overall Dawn-Parkway system review of design day demands and capacity.

The physical gas requirement at Parkway does not change based on the split of system sales service and direct purchase customers. As direct purchase customers return to system sales service, the overall direct purchase customer obligation at Parkway is reduced. For direct purchase customers migrating to system sales service with an allocation of upstream transportation capacity (as per Union's vertical slice methodology) that capacity will be returned to system sales service.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pg 14

Preamble: Union discusses its existing firm transportation contracts with Trunkline Gas Company and Panhandle Eastern Pipe Line.

a) The stated term of the Trunkline/Panhandle contracts are November 1, 2007 through to October 31, 2012. Does Union plan to renew, extend or replace these contracts? If not, why not? If so, please provide the rationale, including landed cost analysis for this contract and all potential alternatives.

b) Union states that "the volumes are obligated at Parkway by a firm Ojibway to Parkway service".

   i) How is this Ojibway to Parkway service provided?

   ii) Does Union contract with itself under an ex-franchise transportation contract? If so, what are the terms of that contract?

   iii) Is the obligation of deliveries from the Panhandle contract discussed at line 19-22 handled the same way? If not, please explain.

Response:

a) Union has extended the existing Trunkline/Panhandle contracts through to October 31, 2017**.**

   Rationale

   Union's 2012-2016 Gas Supply Plan supported the replacement of the expiring Trunkline/Panhandle capacity in order for Union to continue to meet forecasted demand. The landed cost of gas that Union negotiated is competitive with supply flowing on alternative upstream pipelines. The benefits of renewing this capacity are:

   i) The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;

ii) The 5-year renewal supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
iii) It maintains and supports the acquisition of secure supply from a diverse number of gas basins, specifically the Gulf of Mexico, gas suppliers and transportation providers with whom Union has already established commercial relationships;
iv) It has low Unabsorbed Demand Charge ("UDC") cost exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
v) It achieves a fixed-rate toll for the 5-year term providing toll certainty on a portion of Union's supply;
vi) It provides Union receipt and delivery flexibility within the US Midwest and Great Lakes area due to the secondary Receipt and Delivery rights.

The landed cost analysis for this contract illustrates alternatives considered. Please see Attachment 1.

b)

i) The firm Ojibway to Parkway service is underpinned by Union's Ojibway to Dawn service and a Dawn to Union CDA service that Union acquired from TCPL.

ii) No. This service is underpinned by Union's Ojibway to Dawn service and a Dawn to Union CDA FT contract that Union holds with TCPL.

iii) Yes.

2012-2017 Transportation Contracting Analysis

Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/Gj	Point of Delivery
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
Vector	Chicago	0.052	5.8863	0.2500	0.0019	0.0712	0.3231	$6.21	**$ 6.81**	Dawn
Panhandle Longhaul	Panhandle Field Zone	-0.349	5.4854	0.4251	0.0442	0.3203	0.7896	$6.28	**$ 6.88**	Ojibway
Trunkline/Panhandle	Trunkline Field Zone	0.049	5.8841	0.1926	0.0274	0.2507	0.4707	$6.35	**$ 6.97**	Ojibway
Dawn	Dawn	0.675	6.5101	0.0000	0.0000	0.0000	0.0000	$6.51	**$ 7.14**	Dawn
Alliance/Vector	CREC	-0.973	4.8615	1.6991	-0.2875	0.2825	1.6941	$6.56	**$ 7.19**	Dawn
TCPL Niagara	Niagara	0.757	6.5922	0.1386	0.0000	0.0000	0.1386	$6.73	**$ 7.38**	Kirkwall
TCPL SWDA	Empress	-0.859	4.9754	1.9430	0.1330	0.1209	2.1970	$7.17	**$ 7.87**	Dawn

Assumptions used in Developing Long-term Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**2012 $US/mmBtu**	**2013 $US/mmBtu**	**2014 $US/mmBtu**	**2015 $US/mmBtu**	**2016 $US/mmBtu**	**Average Annual Gas Supply Cost $US/mmBtu**	**Fuel Ratio Forecasts Col (G) above**
Henry Hub (NYMEX) $US/mmBtu		$5.11	$5.65	$6.07	$5.94	$6.40	$5.83	
Vector	Chicago	$5.18	$5.69	$6.12	$6.00	$6.44	$5.89	1.21%
Panhandle Longhaul	Panhandle Field Zone	$4.80	$5.33	$5.74	$5.58	$5.98	$5.49	5.84%
Trunkline/Panhandle	Trunkline Field Zone	$5.14	$5.69	$6.12	$6.00	$6.46	$5.88	4.26%
Dawn	Dawn	$5.77	$6.26	$6.77	$6.65	$7.10	$6.51	0.00%
Alliance/Vector	CREC	$4.13	$4.64	$5.11	$5.02	$5.41	$4.86	5.81%
TCPL Niagara	Niagara	$5.85	$6.35	$6.85	$6.72	$7.19	$6.59	0.35%
TCPL SWDA	Empress	$4.23	$4.75	$5.23	$5.14	$5.53	$4.98	2.43%

Sources for Assumptions:

Gas Supply Prices (Cols C & D):	ICF International; April 2011	
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis	
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast	
Foreign Exchange (Col K)	$1 US =	$0.962 CDN
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056
Union's Analysis Completed:	May-11	

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pgs 15-16

Preamble: Union discusses its Union North Transportation Portfolio which now includes firm transportation of 6,143 GJ/d from Michigan to the SSMDA.

a) Union's stated rationale for contracting for 6,143 GJ/d from Michigan to the SSMDA was "to achieve some supply diversity in Union North."

   i) Was supply diversity the only reason for undertaking these contracts? If there were other reasons please provide them.

   ii) Please confirm that Union reduced its FT contracted volumes with TransCanada for service from Empress to the SSMDA. Please provide the amount of the contracted volume reduction.

   iii) Please provide the economic analysis that Union relied upon to make this decision, including the comparison of the cost of serving this market with TransCanada FT and with capacity from Michigan to the SSMDA.

b) Please provide average day and peak day deliveries for each of the last 3 years to the SSMDA.

c) Please break out the service type and volumes by pipeline used to service the SSMDA.

d) Please explain how Union is changing the manner in which it supplies the SSMDA through GLGT backhaul service

e) Does Union include the costs to its customers of changes in TransCanada Mainline tolls as a result of Union's decontracting on the TransCanada Mainline when it evaluates the cost of supply alternatives for Union North? If not, why not?

Response:

a)

i. Introducing supply diversity to the north was not the only reason that Union entered into contracts with MichCon and GLGT to serve the SSMDA.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;
2. The three-year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
3. It introduces to northern customers secure supply from a new gas basin, increasing Union's supply diversity;
4. The transportation path provides transportation portfolio diversity by including two new pipeline suppliers in the North, MichCon and GLGT;
5. Both MichCon and GLGT are able to provide a fixed-rate toll for the contract term providing increased toll certainty on this supply.

ii. Confirmed, Union reduced its FT contracted volumes with TransCanada for service from Empress to the Union SSMDA for system supply by 6,143 GJ/d. For system supply, Union replaced each GJ of TCPL Empress to Union SSMDA with short-haul on TCPL SS Marie to Union SSMDA.

iii. Please see Attachment 1.

b) The average day and peak day deliveries for each of the last 3 years to the SSMDA for Union's system and Bundled Direct Purchase customers, are provided in the following table:

Line No.		**Average Day**	**Peak Day**
1		**GJ**	**GJ**
2	**2011**	12,473	35,232
3	**2010**	11,367	32,228
4	**2009**	11,505	33,694

The table does not include T-Service customers in the SSMDA, since they nominate and deliver their own supply.

c) The service type and volumes by pipeline and path used to service the SSMDA System and Bundled Direct Purchase customers (not T-Service) are detailed in the table below as at January 1, 2012:

Pipeline	**Service Type**	**Path**	**Quantity**
TCPL	FT	Empress-SSMDA	2,000 GJ/d
TCPL	STS – Withdrawal	Dawn-SSMDA	35,022 GJ/d
MichCon	FT	MichCon Generic-Belle River Mills	5,829 mmbtu/d Nov-Mar 3,003mmbtu/d Apr-Oct
GLGT	FT	Belle River Mills – SS Marie	5,829 dth/d
TCPL	FT	SS Marie – Union SSMDA	6,143 GJ/d

d) Please see the response at a) and c) above.

e) Please see the response at Exhibit J.D-14-7-6.

Union Gas Limited
2011-2014 Transportation Contracting Analysis

Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	**Landed Cost $Cdn/Gj**	Point of Delivery
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	**(K)**	(L)
MichCon-GLGT-TCPL to SSMDA	Michigan	0.27	5.44	0.1572	0.0002	0.0921	0.2495	$5.69	**$5.86**	SSMDA
TCPL Empress to SSMDA	Empress	(0.63)	4.54	1.2440	0.0531	0.1013	1.3984	$5.94	**$6.12**	SSMDA

Assumptions used in Devleoping Long-term Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**2011 $US/mmBtu**	**2012 $US/mmBtu**	**2013 $US/mmBtu**	**Average Annual Gas Supply Cost $US/mmBtu Col (D) above**	**Fuel Ratio Forecasts Col (G) above**
Henry Hub (NYMEX) $US/mmBtu		4.70	5.05	5.75	5.17	
MichCon to SSMDA	Michigan	4.96	5.30	6.06	5.44	1.69%
TCPL Empress to SSMDA	Empress	4.06	4.42	5.15	4.54	2.23%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF International; October 2010		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.024	CDN
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	GJs
Union's Analysis Completed:	Jan-11		

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited (“TCPL”)

Reference: Exhibit D3, Tab 2, Schedule 3

Preamble: Table indicating forecast of supply from 2012 to 2016

a) Please explain why the forecast shows:

   i) Western Canadian Firm supply decreasing from 107,848 TJ in 2012 to 70,863 TJ in 2016;
   ii) US Firm supplies decreasing from 43,884 TJ, in 2012 to 18,363 TJ in 2016; and
   iii) Ontario Delivered Supplies increasing from 83,306 TJ in 2012 to 133,103 TJ in 2016.

b) Please provide any economic analysis supporting the above noted changes in forecast supply source. If no analysis was done, please explain why not.

Response:

a)

   i. The decrease in Western Canadian firm supplies in 2016 is the result of the Alliance contract expiry effective November 30, 2015.

   ii. The decrease in U.S. Firm supplies in 2016 is the result of the Vector contract expiry effective November 30, 2015.

   iii. The increase in the Ontario Delivered Supplies is a result of the Alliance and Vector contract expiries noted in the responses to i) and ii) above.

   Under Union’s normal gas planning process, when pipeline contracts expire in the later years of the plan they default to supplies at Dawn until such time as upstream transportation is contracted.

b) There is no economic analysis performed on the changes in forecast supply source as part of the gas planning process.

As new transportation contracts are signed or existing transportation contracts are renewed an economic analysis is performed and filed with the Board in the appropriate proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D3, Tab 2, Schedule 3 and 5

Preamble: Union provides its summary of upstream transportation contracts and gas supply / demand balance forecast for 2012-2016. TransCanada seeks to better understand the possible effects on Union's contracts as a result of Union's Parkway Extension Open Season.

Please provide the changes to these contracts that Union expects will occur if its current Parkway extension Open Season is successful.

Response:

No decision has been made regarding the impact to existing contracts although Union expects to utilize the Parkway Extension Project to reach the Maple point on the TCPL system and to move gas to points north and east. The volumes will be dependent on services and landed costs at that time.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pgs 2 - 3

Preamble: Union discusses principles for gas supply planning, one of which is: "iii) Encourage new sources of supply as well as new infrastructure to Union's service territory;"

Does Union consider the total impact on all Union customers and/or on all Ontario customers resulting from the acquisition of new sources of supply and adding new infrastructure including the effect on the tolls that Union pays to TransCanada? If not, why not? If so, please provide all the analysis that has been done in this regard in the past 10 years when accessing new sources of supply.

Response:

The natural gas markets in North America are going through significant change with traditional basins such as the WCSB and the Gulf in decline and robust supply developing in non traditional area's such as the Marcellus. These changes will require utilities like Union to change their gas supply portfolio to bring in supply from these new competitively priced basins.

Overall, Union's Gas Supply planning process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at a prudently incurred cost. These include:

1) Ensuring secure and reliable gas supply to Union's service territory;
2) Minimizing risk by diversifying contract terms, supply basins and upstream pipes;
3) Encouraging new sources of supply as well as new infrastructure to Union's service territory;
4) Meet planned peak day and seasonal gas delivery requirements; and
5) Deliver gas to various receipt points on Union's system to maintain system integrity.

When considering the renewal of any upstream transportation contracts or evaluating new sources of supply, Union prepares a detailed landed cost analysis that compares the various supply and transportation options to the one under consideration for the delivery area. The analysis incorporates the best available information at the time including approved or pending upstream transportation tolls. Union uses the output of the landed cost analysis, in conjunction with the principles provided above, to determine whether or not it is in the best interest of it customers in that delivery area to pursue a particular supply and transportation option.

Union does not take into account the extent to which the action it takes on behalf of its customers in one delivery area impacts other customers either inside or outside of its service territory. This not only applies to TCPL but also to any other transportation service provider supplying Ontario. For example, Union did not take into account the impact on Alliance's existing customers of not renewing Alliance capacity. Union is however, always looking for the best way to deliver gas to each delivery area while meeting the above 5 stated principles.

Further, Union is not aware of any analysis prepared by TCPL on the impact of it not renewing its Union M12 transportation capacity on Union's remaining in-franchise and ex-franchise customers.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pg 2 - 3

Preamble: Union discusses its five year gas supply plan including key inputs and assumptions.

a) Has Union considered the impact that the reduced TransCanada tolls, as filed in TransCanada's RH-3-2011 Proposal with the National Energy Board (NEB), would have on its customers and on the proposed supply portfolio.

b) If yes, please provide the analysis conducted.

c) If no, please explain why no analysis was done.

d) Please recalculate the forecast of Union's costs required to serve in-franchise sales service and bundled direct purchase customers using TransCanada's Rates as set out in TransCanada's proposal as filed with the NEB in the RH-3-2011 proceeding.

Response:

a) No, Union has not considered the impacts of "proposed" TCPL tolls on its supply portfolio.

b) N/A.

c) Union does not prepare its gas plan or make supply portfolio decisions on the basis of "proposed" tolls. Union uses the applicable approved and/or contracted toll for each of its upstream transportation contracts at the time of completing the plan or making the transportation portfolio decision.

d) Please see Attachment 1. The difference between TCPL's 2012 Interim Contract Costs and TCPL's 2012 Proposed Contract Costs results in a potential savings of up to $70.5 million in 2012 (Column (f), Line 19 Total $208.6 million – Column (g), Line 19 Total $138.1 million).

Union notes that TCPL's 2012-2013 tolls are currently under review and it is premature to anticipate the final approved tolls and their impact on Union's customers.

TCPL Mainline Transportation Toll Impact
on Union's Upstream TCPL Transportation Capacity as at November 1, 2011

Line No.	Union's TCPL Capacity Nov - 2011	Contracted Capacity 2011 GJ/d	TCPL Interim Tolls 2012 ($/GJ)	TCPL Proposed 2012 ($/GJ)	TCPL Status Quo 2012 ($/GJ)	TCPL 2012 Interim Contract Costs ($CDN)	TCPL Proposal Contract Costs 2012	TCPL Status Quo Contract Costs 2012
		(a)	(b)	(c)	(d)	(f) = (a) * 365 * (b)	(g) = (a) * 365 * (c)	(h) = (a) * 365 * (d)
1	Empress - EDA	59,251	2.2429	1.4738	2.585	48,506,335	31,873,305	55,904,800
2	Empress - NCDA	10,756	2.2429	1.3329	2.585	8,805,491	5,232,885	10,148,555
3	Empress - SSMDA	9,143	1.7422	1.0629	2.0232	5,814,061	3,547,105	6,751,813
4	Empress - NDA	67,625	1.7422	1.1657	2.0232	43,002,940	28,773,119	49,938,899
5	Empress - WDA	39,880	1.1329	0.7567	1.2819	16,490,719	11,014,677	18,659,593
6	Empress - MDA	4,522	0.6802	0.526	0.7716	1,122,691	868,179	1,273,549
7	Empress - Union CDA	71,327	2.2429	1.3731	2.585	58,392,455	35,747,773	67,298,808
8	Long Haul Subtotal	262,504				182,134,691	117,057,042	209,976,016
9	SSMDA - Union SSMDA	6,143	0.0606	0.0697	0.5295	135,877	156,281	1,187,242
10	Inj - Parkway (Union WDA)	3,150	1.1018	0.74537	1.26576	1,266,795	856,989	1,455,308
11	Inj - Parkway (Union NDA)	49,100	0.43	0.31739	0.47972	7,706,245	5,688,105	8,597,302
12	WD - Parkway (Union EDA)	68,520	0.2781	0.21576	0.3007	6,955,225	5,396,114	7,520,447
13	Parkway Belt - Union CDA	16,000	0.0686	0.0833	0.0655	400,624	486,472	382,520
14	Parkway Belt - Union CDA	64,000	0.0686	0.0833	0.0655	1,602,496	1,945,888	1,530,080
15	Parkway Belt - Union EDA	30,000	0.2836	0.2163	0.3063	3,105,420	2,368,485	3,353,985
16	Parkway Belt - Union EDA	5,000	0.2836	0.2163	0.3063	517,570	394,748	558,998
17	Dawn - Union CDA	60,000	0.218	0.1708	0.2317	4,774,200	3,740,520	5,074,230
18	Short Haul Subtotal	301,913				26,464,452	21,033,602	29,660,111
19	TOTAL	564,417				208,599,143	138,090,644	239,636,127

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit D1, Tab 1, pg 6, line 10
Exhibit D3, Tab 2, Schedule 3, line 6

Preamble: In Reference (1), Union lists 15.3 TJ of Dawn Delivered Service for 2013, and in Reference (2) lists 79,779 TJ of Ontario Delivered Supplies.

a) Please define the term Dawn Delivered Service.

b) Please define the term Ontario Delivered Supplies.

c) Please break out the 79,779 TJ of Ontario Delivered Supplies to reflect Dawn Delivered Supply, and explain what other supplies make up Ontario Delivered Supplies for each year from 2012 to 2016.

Response:

a) Dawn Delivered Service refers to Dawn sourced supply for Union's sales service customers. Please note that the reference at Exhibit D1, Tab 1, Page 6, Line 10 should have read 15.3 PJ's of Dawn Delivered Service.

b) Ontario Delivered Supplies includes Dawn Delivered Service for Union's sales service customers as well as obligated Dawn and Parkway deliveries for bundled direct purchase customers.

c) Please see Attachment 1.

UNION GAS LIMITED
Gas Supply / Demand Balance
Forecast 2012 to 2016

Line No.	Particulars (TJ)	2012 (a)	2013 (b)	2014 (c)	2015 (d)	2016 (e)
	Ontario Delivered Supplies					
1	Dawn Delivered Service	17,215	15,338	14,854	18,597	69,863
2	Direct Purchase Ontario Deliveries	66,090	64,441	63,062	63,067	63,240
3	Total	83,306	79,779	77,916	81,664	133,103

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit H1, Tab 1, pg s 53 - 54

Preamble: Union discusses the change in methodology for Kirkwall to Dawn C1 Service.

a) Please provide the toll impact of the proposed change to the toll design methodology for C1 Kirkwall to Dawn service on:

   i) Kirkwall to Parkway C1 Service;

   ii) M12-X Service;

   iii) M12 Dawn to Parkway Service; and

   iv) M12 Dawn to Kirkwall Service.

b) Please identify whether C1 Kirkwall to Parkway service, M12-X service, or C1 Kirkwall to Dawn service are allocated costs associated with the Kirkwall facilities modifications.

Response:

a) Please see Attachment 1.

b) All services identified above are allocated costs associated with the Kirkwall metering facilities modifications.

Union Gas Limited
M12/C1 Transportation Demand Charges Impact

		Transportation Demand Charges		
Line No.	Services	Kirkwall Facilities Assigned to C1 Kirkwall to Dawn Demand Charge Only ($\$/10^3m^3$)	As Filed ($\$/10^3m^3$)	% Change
		(a)	(b)	(c) = (b-a) / (a)
1	M12/C1 Kirkwall to Parkway	14.544	14.620	0.5%
2	M12-X	115.689	116.240	0.5%
3	M12/C1 Dawn to Parkway	93.037	93.469	0.5%
4	M12/C1 Dawn to Kirkwall	78.493	78.850	0.5%
5	C1 Parkway to Dawn	22.653	22.771	0.5%
6	C1 Kirkwall to Dawn	46.021	40.159	-12.7%

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 10, Figure 1

Would Union please update the graph of Dawn-Kirkwall's activity to the end of 2011?

Response:

Please see the response at Exhibit J.O-5-2-1.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 10

Are shipper contracts, on Dawn-Kirkwall route multi-year demand based contracts? To what extent do reduced volumes mean reduced revenues? Please discuss and quantify. Please provide a copy of the rate and standard contract(s) used for ex-franchise transmission on Dawn-Kirkwall and Dawn-Parkway.

Response:

Yes. Contracts on Dawn-Kirkwall have been multi-year demand based contracts.

To the extent that contracted capacities are reduced, revenues are reduced per the Monthly Demand Charge applied to the reduced amount of capacity.

Contracts for ex-franchise transmission on Dawn-Kirkwall and Dawn-Parkway can be found at:
http://www.uniongas.com/storagetransportation/resources/standardcontracts/

Rate schedules for ex-franchise transmission on Dawn-Kirkwall and Dawn-Parkway can be found at:
http://www.uniongas.com/storagetransportation/infopostings/pdf/rateschedules/M12_Rate_Schedule.pdf
and
http://www.uniongas.com/storagetransportation/infopostings/pdf/rateschedules/C1_Rate_Schedule.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 11

Has the 375,000 GJ/d of Dawn-Kirkwall capacity turned back by TCPL on October 31, 2010, effective November 1, 2012, been resold under comparable terms, ie. revenue, demand/commodity, and term.

Response:

A portion of the capacity which TCPL turned back on October 31, 2010 was resold effective November 1, 2012. Union also used a portion of this capacity to reduce the requirement to purchase winter peaking service. For details regarding the capacity that was resold effective 2012, please refer to the response at J.C-4-7-5b). This capacity was resold at posted tolls.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 11

What are the remaining terms and volumes of each of the contracts from Dawn-Kirkwall line?

Response:

Customer Name	Quantity (GJ)	Start Date	End Date	
TransCanada PipeLines Limited	125,297	01-Nov-94	31-Oct-15	(1)
Enbridge Gas Distribution Inc.	32,123	01-Apr-04	31-Mar-14	
KeySpan Gas East Corporation d/b/a National Grid	138,600	01-Nov-07	31-Oct-18	
TransCanada PipeLines Limited	146,560	01-Nov-08	31-Oct-14	(2)
TransCanada PipeLines Limited	533,191	01-Nov-08	31-Oct-14	(3)
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	49,500	01-Sep-09	31-Aug-29	
TransCanada PipeLines Limited	53,440	01-Nov-10	31-Oct-13	(4)
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.	31,746	01-Nov-11	31-Oct-16	
Dynegy Gas Imports, LLC	38,306	01-Nov-08	31-Oct-15	
Enbridge Gas Distribution Inc.	35,806	01-Nov-10	31-Oct-14	
National Fuel Gas Distribution Corporation	10,791	01-Nov-10	31-Oct-17	
National Fuel Gas Distribution Corporation	15,904	01-Nov-10	31-Oct-20	

(1) Quantity reduces to 62,602 GJ effective November 1, 2012.
(2) Quantity reduces to 13,336 GJ effective November 1, 2013.
(3) Quantity reduces to 158,003 GJ effective November 1, 2012.
(4) Quantity reduces to 0 GJ effective November 1, 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2

Are they all priced at the M12 rate? What is the difference between C1 Transportation and M12? Please explain fully.

Response:

Yes, the remaining Dawn-Kirkwall contracts are priced at the M12 rate.

The service summary for M12 and C1 services is located on the Union Gas web site at:
http://www.uniongas.com/storagetransportation/services/transportservicesummary.asp

Please see Attachment 1.

Product	Typical Contract	Rate Schedule	Service Type	Term	Rate	Fuel	Overrun	Fuel True Up
C1 Transport	HUB Enhancement	C1	Firm/IT	1 year or less - Daily, Monthly, Seasonal, Annual	Negotiated Maximum rate $75 per C1 Rate Schedule	Negotiated as Fuel (C1 Rate Schedule) or commodity charge	n/a	No
C1 Transport	HUB Enhancement	C1	Firm	more than 1 year but less than 2 years	C1 Rate Schedule	Fuel as per C1 Rate Schedule	C1 Rate Schedule	No
C1 Transport	C1	C1	Firm	2 years or more	C1 Rate Schedule Multi-year prices may also be negotiated, which may be higher than the identified rates.	Fuel as per C1 Rate Schedule	C1 Rate Schedule	No
M12 Transport	M12	M12	Firm	typically 10 years + (expansion)	M12 Rate Schedule	Fuel as per M12 Rate Schedule	M12 Rate Schedule	Yes

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 11

Union states that, effective November 1, 2013, TCPL has turned back 186.6 GJ/d of Dawn-Kirkwall capacity, and that TCPL and two other parties have turned back 122,000 GJ/d of Dawn Parkway service for a total 310,000 GJ/d (122,000 GJ/d Dawn Parkway and 186,000 GJ/d from Dawn-Kirkwall). Why has Union forecast 350,000 GJ/d for 2013 from Dawn-Kirkwall and Dawn Parkway, and what is breakdown between the two.

Response:

The turnback of approximately 310,000 GJ/d described at Exhibit A2, Tab 1, Schedule 1, page 11 reflects the actual turnback notices received. The actual turnback received is less than the forecast of 350,000 GJ/d for 2013. The actual turnback notifications were received after the forecast was completed. A reconciliation between the forecasted turnback and the status of turnback received can be found at the response to Exhibit J.C-4-2-1 a).

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

What is the breakdown in gas throughput on Dawn-Kirkwall and Dawn Parkway routes as between gas utilized in Union franchise area, gas utilized in Enbridge franchise, gas used in Quebec, and gas used in the United States. Please list the names of the ex-franchise shippers, which currently hold capacity on Dawn-Kirkwall and Dawn Parkway, the amounts of capacity held, and the revenues paid in 2012.

Response:

Union does not have the ability to track where gas is finally utilized. Union's systems track gas nominated to flow on Union Gas pipeline capacity from and to interconnecting pipelines. Union does not track the point of ultimate consumption.

The names of ex-franchise shippers, which currently hold capacity on Dawn-Kirkwall and Dawn Parkway, the amounts of capacity held, and the revenues paid in 2011 are detailed in Attachment 1.

Ex-franchise Dawn-Kirkwall and Dawn-Parkway Capacity

Path	Shipper	2011 Revenue	November 1, 2011 Quantity
Dawn to Kirkwall	Dynegy Gas Imports, LLC	912,448.92	38,306
	TransCanada PipeLines Limited	28,218,294.80	986,804
	Consolidated Edison Company of New York, Inc.	126,031.62	31,746
	Enbridge Gas Distribution Inc.	1,618,068.84	67,929
	KeySpan Gas East Corporation d/b/a National Grid	3,302,691.61	138,600
	National Fuel Gas Distribution Corporation	635,874.96	26,695
	Thorold CoGen L.P.	1,589,172.17	49,500
Dawn to Parkway	1425445 Ontario Limited o/a Utilities Kingston	377,348.19	13,435
	Boston Gas Company d/b/a National Grid	320,139.03	11,440
	EnergyNorth Natural Gas, Inc. d/b/a National Grid	120,853.46	4,317
	Portlands Energy Centre L.P. ,by its General Partn	3,460,800.00	100,000
	Suncor Energy Products Partnership	419,760.00	15,000
	Terra International (Canada) Inc.	378,213.00	7,065
	The Brooklyn Union Gas Company d/b/a National Grid	1,413,373.89	87,189
	The Corporation of the City of Kitchener	111,936.00	4,000
	The Narragansett Electric Company d/b/a National Grid	5,041.78	1,081
	TransCanada PipeLines Limited	7,541,072.32	183,934
	U.S. Steel Canada Inc.	485,550.36	17,351
	Vermont Gas Systems, Inc.	13,992.00	20,500
	Yankee Gas Services Company	1,932,463.08	69,056
	Ag Energy Co-operative Ltd.	53,636.00	3,500
	Bay State Gas Company	778,039.20	27,803
	BP Canada Energy Company	559,680.00	20,000
	Central Hudson Gas & Electric	327,558.51	16,259
	Colonial Gas Company d/b/a National Grid	181,196.40	6,475
	Connecticut Natural Gas Corporation	973,964.46	40,146
	Consolidated Edison Company of New York	101,791.80	21,825
	Enbridge Gas Distribution Inc.	61,077,253.79	2,157,173
	Gaz Metro Limited Partnership	8,036,144.93	287,000
	Greater Toronto Airports Authority	209,880.00	7,500
	GreenField Ethanol Inc.	83,952.00	3,000
	J. Aron & Company	1,399,691.59	50,000
	KeySpan Gas East Corporation d/b/a National Grid	1,321,968.73	83,771
	Niagara Mohawk Power	257,102.30	55,123
	Northern Utilities, Inc.	178,489.91	6,333
	Sithe Canada Inc.	5,076,960.00	140,000
	St. Lawrence Gas Company, Inc.	301,807.44	10,785
	The Southern Connecticut Gas Company	1,641,401.52	58,655
	TransAlta Cogeneration, L.P.	330,463.08	11,809
	TransCanada Energy Ltd./TransCanada Power	3,693,888.00	132,000

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Exhibit A2, Tab 1, Schedule 1, page 11

How does Union estimate:

i) the transportation capacity at risk of turn back in the years "beyond 2013" to be greater than 800,000 GJ/d? Please provide details.

ii) Please provide the estimated turn back in each of the years 2014 through 2018.

Response:

i) When estimating the turnback risk, Union reviewed the contracts that are used to export gas to the US Northeast. The contracts interconnect with TCPL at Parkway and Kirkwall with gas flowing through export points on the TCPL system (Chippawa, Niagara, Iroquois, East Hereford & Napierville). These contracts are most at risk and may not be renewed given the alternative and emerging supplies in the Marcellus basin.

ii) During the preparation of this response, an inconsistency was identified.

An updated Exhibit A2, Tab 1, Schedule 1, Table 4 is included as Attachment 1.

Attachment 2 outlines the annual Dawn to Parkway and Dawn to Kirkwall contracts that are subject to annual renewals, and the Dawn to Parkway and Dawn to Kirkwall contracts that Union considers to be at risk of turnback.

UNION GAS LIMITED
Impact of M12 Turnback
Demands as of November, 1 (GJ/d)

Line		Outlook 2011 (a)	Forecast 2012 (b)	Forecast 2013 (c)	At Risk 2014-2019 (d)
	Annual Impacts (GJ/d)				
1	Dawn - Kirkwall	(317,000)	(375,188)	(286,198)	(305,137)
2	Dawn - Parkway			(67,000)	(509,473)
3	Total	(317,000)	(375,188)	(353,198)	(814,610)
	Cumulative Impact (GJ/d)				
4	Dawn - Kirkwall	(317,000)	(692,188)	(978,386)	(1,283,523)
5	Dawn - Parkway		-	(67,000)	(576,473)
6	Total	(317,000)	(692,188)	(1,045,386)	(1,859,996)
	Cumulative Revenue Impact ($000's)				
7	Dawn - Kirkwall	$ (1,258)	$ (9,009)	$ (18,086)	$ (32,618)
8	Dawn - Parkway	$ -	$ -	$ (324)	$ (18,564)
9	Total	$ (1,258)	$ (9,009)	$ (18,410)	$ (51,181)

Note: All contract changes assumed to commence November 1st.

UNION GAS LIMITED
Impact of M12 Turnback
Demands as of November, 1 (GJ/d)

Line		Renewals 2014	Renewals 2015	Renewals 2016	Renewals 2017	Renewals 2018	Renewals 2019	Renewals 2014-2019
	Annual Expiring Contracts (GJ/d)							
1	Dawn - Kirkwall	(747,680)	(163,603)	(31,746)	(10,791)	(138,600)	-	(1,092,420)
2	Dawn - Parkway	(2,087,569)	-	(369,379)	(193,418)	(379,540)	(81,704)	(3,111,610)
3	Total	(2,835,249)	(163,603)	(401,125)	(204,209)	(518,140)	(81,704)	(4,204,030)

Line		At Risk 2014	At Risk 2015	At Risk 2016	At Risk 2017	At Risk 2018	At Risk 2019	At Risk 2014-2019
	Deemed at risk for Turnback							
4	Dawn - Kirkwall	-	-	(31,746)	(10,791)	(262,600)	-	(305,137)
5	Dawn - Parkway	-	-	(177,762)	(193,418)	(116,689)	(21,604)	(509,473)
6	Total	-	-	(209,508)	(204,209)	(379,289)	(21,604)	(814,610)

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 12, Table 4

Please provide the calculation underpinning the dollar value of the revenue impact in line 9 of Table 4. How many years out in the calculation done. What discount rate is used to derive the $48,116 million in that revenue?

Response:

Below is a sample of the calculations used for the revenue impact in Line 9 of Table 4. This was done for each year of the analysis. No discounted rate was used.

Calculation:
Initial year of expiry:
Volumes x effective M12 rate for path x number of months
Example - 2011 – Dawn to Kirkwall

317,000 x 1.985 x 2mths = $1,258,490
Subsequent years:
Volumes x M12 rate for path x 12 months (entire year impact)
Example – 2012 – Dawn to Kirkwall
(317,000 x 1.985 x 12) + (375,188 x 1.978 x 2) = $9,008,556

NOTE:
2011 rates were per Board approved 2011 rates as per EB-2010-0148.
2012 rates were per Board approved 2012 rates as per EB-2011-0025.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 12, Line 8, Table 4

Please confirm that the total revenue impact of 2011 and 2012 turnback has totally offset by reselling of the services.

Response:

Not confirmed. Union notes that there is a negative revenue impact for the turn back in 2013. Please see Exhibit C1, Tab 3, Schedule 1 for the changes to M12 Transport contract demands, and Exhibit C1, Tab 3, Schedule 2 for the associated impacts to revenue.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Ref: Exhibit A2, Tab 1, Schedule 1, pages 12-13

i) What is the current status of the TCPL's Eastern Extension application to the NEB to remove congestion at Maple?

ii) Is the NEB acting on it? Please provide copies of, or links to, the TCPL application and the NEB's responses to date.

iii) Has it become part of TCPL current mainline tolls application? Please provide details.

iv) What is the likelihood, in Union's view, that TCPL will eliminate the congestion between Parkway and Maple, and when?

v) Please explain what is meant by the sentence "Union is working to repurpose" the turn back of Dawn-Kirkwall transmission services as Dawn Parkway transmission service".

Response:

i) At the time of this filing, TCPL has filed its evidence, received and responded to interrogatories, interested parties have submitted comment letters and TCPL is awaiting a Decision.

ii) TCPL's Section 58 Application for the 2012 Eastern Mainline Expansion has been filed with the NEB and can be accessed by clicking on the following link:
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=752993&objAction=browse

On March 21, 2012, TCPL responded to Intervenors questions and comments and now awaits a decision from the NEB which they had requested by May 1, 2012.

The following links are provided to access NEB's IRs and TCPL's responses:
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=781774&objAction=browse
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=792139&objAction=browse

iii) TCPL's Section 58 Application for the approval of the construction or modification of facilities required, for the 2012 Eastern Mainline Expansion is separate from the Mainline's 2012-2013 Tolls Application (RH-003-2011) proceeding. Facilities costs for tolling purposes will be addressed in the Mainline Tolls Proceeding.

iv) The 2012 Eastern Mainline Expansion Project does not eliminate the congestion between Parkway and Maple. The project is sized to accommodate only new contracts beginning November 2012, not necessarily addressing the full current market demand.

Both Union and TCPL have Open Seasons underway that will assess and further address the Parkway to Maple constraint.

v) Union recognizes that the decline in exports of natural gas into the U.S. at TCPL's export points (particularly, Chippawa and Niagara) is long-term, if not permanent, as a result of the emergence of Marcellus shale supply. As exports decline, the need for parties to hold Dawn-Kirkwall capacity also declines.

As Union has received notices of de-contracting of Dawn-Kirkwall capacity, Open Seasons have been conducted in order to offer this capacity to the marketplace as Dawn-Parkway capacity (i.e. repurposed).

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Pages 14-15

Please provide links to any IRs (and TCPL's responses to those IRs) and evidence filed by Union in the TCPL's 2012/2013 mainline tolls application, which deal with TCPL's toll redesign proposals, described on pages 14-15, including the elimination of FT RAM.

Response:

The following links provided pertain to the FT RAM IRs filed in TCPL's 2012 and 2013 Mainline Tolls Application (RH-003-2011) inclusive of TCPL's responses:

https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=772304&objAction=browse

- Tenaska questions 1.15 – 1.35
- National Energy Board 2.36

https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=787853&objAction=browse

- Manitoba Hydro question 2.13
- Gaz Métro 77
- Tenaska Marketing 2.2-2.4

Union's evidence filed collectively by the Market Area Shippers (MAS),which includes Enbridge Gas Distribution Inc. and Gaz Métro Limited Partnership, can be accessed by the following link
https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=797406&objAction=browse

Please refer to MAS Evidence, Section C and D, for an explanation of the MAS Proposed Toll Design and Section H for the benefits of retaining the FT RAM service.
The benefits and rationale of the MAS Proposed Toll Design and the retention of the FT RAM service can be found on the MAS Alternative Proposal, pages 3-14.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 15, Line 11

Please explain how TCPL's elimination of FT RAM "severely limits Union's ability to sell exchanges and other upstream transportation services". Please quantify the answers to the extent possible.

Response:

If the FT RAM program is eliminated, Union's ability to sell exchanges will be limited.

Please see the response at Exhibit J.C-4-7-10 a) and Exhibit J.C-4-7-9, Attachment 1.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref:

Please provide the materials provided to Union by TCPL, as part of the mainline toll application, or otherwise, which describe the FT RAM service.

Response:

Below are links to the publically available materials provided by TCPL that describes the FT RAM service:

1. http://www.transcanada.com/customerexpress/docs/ml_service_offerings/CE_RAM_Description_June17_2010.pdf

2. https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92843/665035/711778/718015/745827/B5-11__-_Section_8.0_Service_and_Pricing_(Revised)_A2G7R8?nodeid=745717&vernum=0 (2012-2013 Mainline Application, Section 8, Service and Pricing, pages 29-31)

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 14, Lines 10-19

On which segments of TCPL system is service offered pursuant to "short haul tolls". Please describe each "short haul segment" and its toll, identify the receipt and delivery point for the service, and the competitive threats to each segment of the TCPL system which is the subject of a "short haul" toll, in respect of which TCPL has, in Union's view, submitted, in the mainline tolls case, a proposed short haul toll which is not sustainable.

Response:

On the TransCanada Mainline, the term long-haul represents gas transported from Western Canada (ie. from Empress or Emerson) to Eastern markets, including Ontario, Quebec and export points to the North East United States. Short-haul paths represent all other paths, including gas that is transported from receipt points to delivery points within Western Canada (including to Saskatchewan and Manitoba) such as Empress to Saskatchewan Zone, and from receipt points to delivery points within the Eastern (Ontario, Quebec and export points to US NE) markets such as Parkway to Iroquois.

Eastern Short Haul Path Tolls

Line No.	Path	2012 TCPL Interim Tolls ($C/GJ)	2012 TCPL Proposed Tolls ($C/GJ)	2012 MAS Proposed Tolls ($C/GJ)	2013 TCPL Proposed Tolls ($C/GJ)	2013 MAS Proposed Tolls ($C/GJ)
1	Dawn to Union CDA	0.218	0.170	0.157	0.147	0.132
2	Dawn to GMI TQM EDA	0.659	0.749	0.501	0.697	0.414
3	Parkway to EGD CDA	0.107	0.100	0.068	0.082	0.058
4	Parkway to Union CDA	0.069	0.083	0.041	0.067	0.036
5	Parkway to Iroquois	0.354	0.262	0.269	0.230	0.223
6	Niagara to Union CDA	0.133	0.109	0.084	0.091	0.072
7	St.Clair to Union SWDA	0.063	0.076	0.035	0.056	0.032

Union's focus for competitive Mainline short-haul tolls is in the Eastern markets where its franchise and major markets are located. However the need for *competitive and sustainable* Mainline tolls applies to both long-haul and short-haul paths. Union, as part of the Market Area Shippers (MAS), addressed this in its evidence filed in TCPL's RH-003-2011 Proceeding. Please see the response at Exhibit J.D-14-16-12.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref:

a) Page 16, line 8: Please provide the average short-term peak storage price sold in 2008, 2009, 2010, and 2012, and (estimated) for 2013. What other factors, in addition to the smaller differential between summer and winter seasonal prices affect demand and supply for Union's short term peak service? What are the underlying factors driving the decrease in price volatility?

b) Can Union's customers that require high deliverability storage service, eg. power plants, effectively access the necessary amounts of storage service in a timely manner, from storage facilities provided (other than Union and Enbridge), and the other, very small, Ontario suppliers? Please answer separately for customers in the Union franchise area and the Enbridge franchise area, and in Quebec. Please include in the answer what type of transportation services will need to be contracted on which pipelines, and an assessment of whether such service is currently available.

Response:

a) Please see Attachment 1.

   Factors that can impact the Short-term Peak Storage value include availability of summer vs. winter supply, weather, forecasted winter demands, storage inventory levels throughout North America, and availability of takeaway capacity, interest rates and perceived value deemed by the customer.

   As indicated in Exhibit A2, Tab 1, page 15, "the significant growth in North American natural gas supplies attributable to shale gas production" has decreased price volatility.

b) Power plants can access high deliverability storage services from Union in a timely manner.

   Transportation services required are dependent upon the location of the plant and whether it is located in-franchise or ex-franchise.

   In-franchise power plants east of Dawn may require Dawn to Parkway capacity in order to meet Parkway supply obligations. In-franchise power plants west of Dawn would be served by the integrated utility assets and would not be required to contract for their own transportation capacity.

Ex-franchise power plants east of Dawn would be required to contract Dawn-Kirkwall or Dawn-Parkway capacity (based on their location) as well as take-away capacity on TransCanada to their final receipt point in either the Enbridge franchise or in Quebec.

Ex-franchise power plants west of Dawn would be required to contract for transport out of the Dawn-Yard as well as take-away capacity on any of the interconnecting pipelines that would ultimately serve the power plant location.

The assessment of the availability of any of these services is dependent on the size of the power plant in question.

UNION GAS LIMITED
Southern Operations Area
Average Value of Short-term Peak Storage
($ CDN/GJ)

Particulars	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Short-term Peak Storage	1.39	1.64	1.39	0.66	0.55	0.85

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: At page 14 of the 2011 Annual Report, Union states that:

> "We have taken steps to allow for the emerging Marcellus Shale gas suppliers to serve our Ontario system customers beginning in 2012, including contracting for firm transportation capacity on other pipelines to facilitate moving this supply to Dawn, and ultimately to our customers".

How much capacity, on what terms, on which pipelines, has Union contracted for in order to facilitate moving Marcellus Shale gas to supply to Ontario customers? What other steps were taken to do this? Please discuss each initiative separately and thoroughly.

Response:

Union entered into a TCPL open season for Niagara to Kirkwall capacity and was awarded capacity to commence November 1, 2012. The capacity is for 21,101 GJ/d for the term November 1, 2012 through October 31, 2022. This will allow gas sourced in the Marcellus to be transported from TCPL's import point at Niagara to the Union system at Kirkwall.

To support the above TCPL project, Union will complete the Kirkwall Flow reversal project for November 1, 2012. This will allow gas moved from Niagara and received at Kirkwall to be moved on the Union system.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: At page 14 of the 2011 Annual Report, Union states:

> "Union Gas applied to the OEB in 2010 and 2011 for transportation service enhancements to respond to the changing flow patterns. These services were approved by the OEB and will enhance access to emerging supply basins and provide enhanced flexibility to attract gas to Dawn…".

a) What service enhancements are being referred to here? Please provide details, including reference to the OEB decisions and applications referred to.

b) Which emerging supply basins will enjoy increased access to Dawn as a result of this? Please provide a detailed discussion.

c) Please describe in detail, the "enhanced flexibility" referred to in the quote from the Annual Report. Please discuss and show how such flexibility will enhance Dawn's and Ontario's attractiveness as a gas market for emerging supply basins.

Response:

a) The service enhancements include new services such as M12-X, C1 Kirkwall to Dawn ,C1 Kirkwall to Parkway and M12 Kirkwall to Parkway that will allow gas to be received at Kirkwall and access Union delivery points. The M12-X and C1 Kirkwall to Dawn services were approved in the EB-2010-0296, Decision and Order dated November 30, 2010. The Kirkwall to Parkway services were approved in the EB-2011-0257, Decision and Order dated September 13, 2011.

b) These services facilitate access of Marcellus and Utica shale gas, and any other gas supply with transportation access to the National Fuel Gas, Empire State Pipeline, Dominion Transmission and Tennessee Gas Pipeline systems, to Dawn and Ontario. These pipeline systems directly or indirectly connect to Gulf Coast, mid-continent and Utica shale gas basins as well as U.S. Rockies production basins. Connecting the emerging basins to the gas consuming market regions is leading to new pipeline and storage infrastructure in North America.

c) The enhanced flexibility refers to the multiple receipt and delivery points and bi-directional flow options on the Union system offered through the M12-X service. In addition, Kirkwall is now offered as a receipt point. These new services provide gas received at Kirkwall, through Niagara and Chippawa via the TCPL system, access to the Dawn Hub where it can be stored and delivered to downstream eastern markets such as Ontario, Quebec and U.S. Northeast markets.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, T1, Page 2

Please file a copy of Union's five year Gas Supply Plan completed in 2011.

Response:

The results from Union's Gas Supply Plan completed in 2011 are found at Exhibit D3, Tab 2, Schedule 1 and Exhibit D4, Tab 2, Schedule 1, respectively. Union's Gas Supply Plan process focuses on the first two years and the remaining three years are based on the second year's results. Therefore, years 2014 to 2016 are not materially different than 2013 and have not been provided.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, T1, Page 2

Please confirm that by use of the term "unbundled service", in line 21, Union means a transportation service, provided to a customer which does not include load balancing or storage. Such a customer would need to contract separately for storage and load balancing. Please provide a copy of, or a link to, the unbundled rate and typical contract.

Response:

A customer taking unbundled service from Union can elect to take an allocation of cost-based storage from Union. The customer is responsible for managing their own load balancing and storage account.

http://www.uniongas.com/business/yourbusiness/energymarketers/contracts/index.asp

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 4

Please describe in detail "TCPL Dawn Diversion". Is this a tariffed service offered by TCPL? If so, please provide a link to TCPL documents.

Response:

Diversions are a tariffed service offered in conjunction with other services by TCPL.
A diversion is the ability to nominate and transport gas to a secondary delivery point. Links are provided below using TCPL Firm Transportation ("TCPL FT") as the primary service example.

TCPL General Terms and Conditions – Amongst other references, Sheet No. 4 has the "Diversion" and "Daily Diversion Quantity" definitions
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/19gtc.pdf

TCPL STS Toll Schedule – 3.1(f)(i) "Daily Diversion Quantity" definition
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/06_STSTollSchedule.pdf

TCPL FT Toll Schedule – Section 6 Alternate Receipt and Diversion of Gas
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/05_FTTollSchedule.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 5

Please explain in detail how the STS withdrawal service works in the winter. Is this a backhaul service where gas is dropped off by TCPL to Union North, and that gas is essentially returned to TCPL at Dawn?

Response:

In accordance with the terms of the STS contract and tariff, on any day during the winter period, TCPL accepts gas from Union at Parkway and transports and delivers the gas to Union in Union's Northern, North Central, Eastern and Western delivery areas. Also, on any day during the winter period, TCPL accepts gas from Union at Dawn and transports and delivers the gas to Union's Sault Ste. Marie delivery area. In the summer, the opposite occurs as gas not needed in the various delivery areas on any given day is nominated to be put into storage.

Union nominates this service on the TCPL system but is not privy to the methods that TCPL uses to physically move the gas from Parkway and Dawn to the respective delivery areas.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Please explain and/or provide link to material which explain Union's contractual pool rights with respect to STS.

Response:

Storage Transportation Service (STS) is a TCPL service that allows Union to move excess volumes from the Northern and Eastern operations areas, to storage in the summer and to withdraw those volumes in the winter to serve primarily weather-driven demands.

Pooling rights are Union's ability to group STS rights in various delivery areas and use them in other areas. This provides Union with the flexibility needed to effectively serve the Northern and Eastern areas of its system.

On a planned basis, this level of STS is designed to work in conjunction with firm transportation capacity to serve demands in the most cost effective manner.

TCPL links to the material to explain STS and the associated pooling are listed below:
High level service overview
http://www.transcanada.com/customerexpress/2840.html

STS Toll Schedule
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/06_STSTollSchedule.pdf

Pro-Forma Contract
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/22_STSContract.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 5, Lines 17-18

Please explain the reason for the increase in MDC to 10.4 PJ in 2013 from 4.4 PJ in EB-2005-0520. BOMA was unable to isolate the reasons for this increase from the discussion of volumes in Mr. Gardner's and Ms. Van Der Paelt's evidence, Exhibit C, T1 and T2.

Response:

The increase in UDC from 4.4 PJ's in 2007 to 10.4 PJ's in 2013 is the result of a decline in weather-normal throughput in the General Service (Rate 01, 10) and Contract (Rate 20T) markets in Union's Northern and Eastern Operations Areas.

The majority of the decline is in the General Service markets as weather-normal throughput has fallen approximately 4.1 PJ's from 2007. The remainder of the decline (approximately 1.8 PJ's) is in the sales service and bundled portions of the Rate 20T rate class.

Union continues to hold capacity on TCPL and Michcon/GLGT in excess of that required to meet normal weather loads in order to serve peak day firm loads for sales service and bundled customers in its Northern and Eastern Operations Areas.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Page 7, Line 5

Please explain, in detail, by way of a few examples, what is meant by the statement that "Union still retains load balancing obligation related to weather variances relative to February inventory checkpoints and March weather and consumption variances" (our emphasis) for both sales service and bundled direct purchase customers.

Response:

Union must ensure it has sufficient gas in storage in February and March to maintain operational integrity.

As part of the load balancing directive in RP-2003-0063, Union implemented checkpoint balancing for bundled direct purchase customers and Union's sales service customers. The February checkpoint requires that direct purchase customers and Union's sales service customers not be below their forecasted inventory level on February 28. In the event that direct purchase customers are below their inventory forecast (consumption exceeded deliveries) and do not deliver incremental gas to correct the inventory level, Union purchases and delivers gas on their behalf to maintain operational integrity.

Union manages all weather risk post-February 28. If weather past the February checkpoint is colder than normal driving higher than expected consumption for both sales service and bundled direct purchase customers, Union may need to purchase and deliver additional gas to maintain operational integrity.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, Page 13, Line 16

Please provide, in detail, an explanation of why Union elected not to renew the Alliance contract beyond December 1, 2015.

Response:

Please see the response at Exhibit J.D-14-5-2.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, Page 13, Line 20

What are the revised provisions in the Vector contract? How did Union decide whether to extend the Vector contract beyond November 30, 2015?

Response:

The decision whether to extend the Vector contract beyond November 30, 2015 has not yet been made.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, Page 15, Line 7

What is the receipt point(s) for the 71,327 GJ/d of TCPL capacity?

Response:

As indicated at Exhibit D1, Page 15, Line 8, the receipt point for the referenced capacity is Empress.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: D1, Page 12

Does Union hold transmission service on National Fuel Gas Transmission or another US pipeline for the 21,101 GJ/d, in Marcellus Gas, or does it purchase the gas at Niagara? If Union holds capacity on a US pipeline, from which basin and from whom is the gas sourced?

Response:

Union does not hold transmission service on a U.S. pipeline for the 21,101 GJ/d. Union intends to purchase the gas at Niagara once the contract is executed and comes into effect, which is anticipated to be November 1, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Natural Gas Reporting & Record Keeping Requirements (RRR) rule for gas utilities; Exhibit A3, Tab 2

Natural Gas RRR 2.1.6 states that

> A utility shall provide the Board annually, by the last day of the fourth month after the financial year end, audited financial statements for the preceding financial year for the corporate entity regulated by the Board. **Where the financial statements of the corporate entity regulated by the Board contain material businesses not regulated by the Board, the utility shall disclose the information separately according to the segment disclosure provisions** in the Canadian Institute of Chartered Accountants Handbook. [Emphasis added]

It appears that there is no segmented information disclosed for Union's regulated business vs. unregulated business in Union's 2010 and 2011 audited financial statements filed in Exhibit A3 Tab 2.

a) Please explain whether the unregulated business is considered by Union as material business in 2010 and 2011.

b) If the unregulated business is not considered by Union as material business in 2010 and 2011, please provide Union's threshold for material business in 2010 and 2011.

c) Please provide Union's external auditor's opinion on management's assessment and decision of not disclosing the segmented information.

Response:

a) Union does not consider its unregulated business a reportable segment as defined by the Canadian Institute of Chartered Accountants Handbook.

b) Union evaluates the need for reportable segments based on the management approach and the information used by the chief operating decision maker.

c) Union's external auditors have provided an unqualified audit opinion on the consolidated financial statements.

UNION GAS LIMITED

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

Ref: Exhibit D3, Tab 3, Schedule 2, page 1 line 29

Please break out the Non-Utility Operation and Maintenance allocation of $13,625,000 by Account Code, using the same format as Exhibit B3, Tab 3, Schedule 1.

Response:

The costs included in the non-utility operating and maintenance allocation of $13,625,000 are operating and maintenance costs only and do not include other costs as identified in Exhibit B3, Tab 3, Schedule 1.

UNION GAS LIMITED

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

Ref: Exhibit H1, Tab 1, Appendix B

Please break out the Unregulated Forecast amounts in column (b) by Account Code, using the same format as Exhibit B3, Tab 3, Schedule 1.

Response:

Union's unregulated rate base is not part of Union's rebasing application and has not been provided.

UNION GAS LIMITED

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

Ref: Exhibit D1, Tab 1, page 3

a) Has the amount of storage integrity space changed during the 2007 through 2012 period? If yes, please provide the amount of storage integrity space in each of 2007 through 2012 that is comparable to the 9.5 PJ.

b) The evidence indicates that one of the key assumptions used is that there is no migration between system sales service and bundled direct purchase customers. Please provide the number of customer and the associated volumes associated with system sales service and bundled direct purchase for each of 2007 through 2011 and the forecasts for 2012 and 2013.

Response:

a) The amount of storage integrity space did not change during the 2007 through 2012 period. The amount of system integrity space for the period was 9.7 PJ.

b) Please see Attachment 1.

Systems Sales vs Bundled Direct Purchase
Year ended December 31

Line No.	Customer Count	2007 Actual (a)	2008 Actual (b)	2009 Actual (c)	2010 Actual (d)	2011 Actual (e)	2012 Forecast (f)	2013 Forecast (g)
1	Direct Purchase	463,516	435,831	394,453	331,742	241,859	316,115	316,110
2	Systems Sales	825,684	873,435	930,437	1,011,899	1,118,042	1,063,027	1,083,318
3	Total	1,289,200	1,309,266	1,324,890	1,343,641	1,359,901	1,379,142	1,399,428

Line No.	Volume	2007 Actual (a)	2008 Actual (b)	2009 Actual (c)	2010 Actual (d)	2011 Actual (e)	2012 Forecast (f)	2013 Forecast (g)
	10^3 m^3							
4	Direct Purchase	4,161,957	4,053,780	3,665,676	3,207,570	2,993,677	2,919,510	2,846,929
5	Systems Sales	3,071,113	3,263,347	3,243,359	3,269,081	3,727,786	3,587,187	3,448,420
6	Total	7,233,070	7,317,127	6,909,036	6,476,651	6,721,463	6,506,697	6,295,349

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit D1, Tab1, Page3/ 4

There are no material changes in the proposed 2012 – 2016 Gas Supply Plan from the Gas Supply Plan filed in Union's 2007 rates proceeding (EB-2005-0520).

Please provide the amount of storage integrity space during IRM 2007 -2012 and compare to the 2013 9.5 PJ.

Response:

Please see the response at Exhibit J.D-16-2-1.

UNION GAS LIMITED

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

Ref: Exhibit G1, Tab 1, page 4, line 1

Union states that the "Excess Utility Storage category includes the system integrity space costs for short-term storage and non-utility storage operations."

a) Please explain why storage integrity space costs for non-utility storage space are allocated to the Excess Utility Storage.

b) Please break out the Revenue Requirement of $419,000 that has been allocated to Excess Utility Storage Space for System Integrity costs (Exhibit G3, Tab 2, Schedule 11, Page 2) to show (a) the System Integrity costs associated with the 13.0 PJ of Excess Utility Space that is included in the Excess Utility Storage Cross Charge and (b) the System Integrity costs associated with the 66.5 PJ of non-utility storage space (see Table 1, Line 2 in Exhibit G1, Tab 1, Page 6).

Response:

a) The 100 PJ of storage space reserved for in-franchise demands includes space reserved for system integrity, as per the Board's Decision in NGEIR (EB-2005-0551). As described at page 10 of the Board's Decision with Reasons:

> "*Union reserves….contingency space related to its needs as system operator*".

Accordingly, Union has allocated system integrity costs associated with the non-utility storage business to the Excess Utility Storage Space category in the cost allocation study. The system integrity costs of the non-utility storage business are included in the non-utility cross charge and paid for by the non-utility. This approach recognizes that system integrity space is a utility function required to support the integrity of the system as a whole for all customers.

b) The breakdown of the $419,000 of system integrity costs allocated to Excess Utility Storage Space is:

   a. Excess Utility Space (13 PJ) = $75,300
   b. Long-Term Storage Space (66.5 PJ) = $343,500

Total system integrity costs of $419,000 are included in the calculation of the Excess Utility Storage Space non-utility cross charge of $4.569 million.

UNION GAS LIMITED

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

Ref: Exhibit G1, Tab 1, page 4, lines 8-12

Union states "Union requires 6.0 PJ of filled space to meet winter operational requirements resulting from system upsets, imbalances and forecast variances. Of the 6.0 PJ filled space, Union requires 1.2 PJ for storage operating constraints (hysteresis). Union also requires 3.5 PJ of empty space on November 1st to manage late season injection demands, of which 0.7 PJ of empty space is reserved to manage storage operating constraints (hysteresis)."

a) Is the 3.5 PJ left empty in the fall, subsequently filled in December to become part of the 6.0 PJ of storage needed full in the winter to handle operational requirements?

b) If not, why not?

Response:

a) The 3.5 PJ left empty in the fall is not filled in December.

b) Refilling the 3.5 PJ left empty in the fall would require system gas supplies to be increased during the winter by 3.5 PJ and decreased in the following summer injection period by 3.5 PJ resulting in a potentially higher supply cost to in-franchise customers. These costs would be highly variable depending on gas price spreads. Conversely, the cost of maintaining the empty system integrity space is fixed.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit D1, Tab 9
Exhibit G1, Tab 1
Exhibit G3, Tab 5, Schedule 23, Pages 5 and 6

a) Union indicates that in EBRO 499, 9.7 PJ of integrity space was required consisting of 9.1 PJ of southern storage and 0.6 PJ of Northern LNG. What is the deliverability associated with each of these storage resources?

b) Although the aggregate integrity space is proposed to decline from 9.7 PJ to 9.5 PJ, Union indicates that it is proposing to increase that portion of the integrity space related to storage pool hysteresis by a factor of 4 from 0.5 PJ to 2.0 PJ (from EB-2005-0520).

   i. Please identify the individual storage pools that are now experiencing increased hysteresis.

   ii. When did the change requiring additional integrity space to account for pool hysteresis begin to occur?

   iii. Has the additional hysteresis been influenced in any way by any of the storage development programs on existing pools (including, but not limited to, adding additional wells, delta pressuring, lowering cushion, down hole simulation programs, adding compression or debottlenecking gathering lines etc.) that Union has implemented over the last 10 years?

c) In Exhibit D1, Tab 9, Union describes hysteresis as the effective reduction in reservoir pressure caused by well interference which lowers deliverability performance (i.e. rate of withdrawals from storage). Union indicates in Exhibit G1, Tab 1, Page 4 that 1.2 PJ of the integrity space will be filled on November 1 while 0.7 PJ of the integrity space will remain empty on November 1 to manage late season injections. Please explain if hysteresis space is required to manage lower deliverability or withdrawal performance, why it is necessary to reserve this empty integrity space to accommodate late season injections.

d) In Exhibit G1, Tab 1, Page 4, Union indicates that it is reserving 3.5 PJ space for late season injections.

   i. Please explain what drives the need for late season injections?

ii. If late season injections are as a result of choice of when to purchase and inject gas into storage, why is this choice an integrity issue?

e) Is the hysteresis problem that Union is experiencing not simply a downgrading of overall storage deliverability performance that results in a lowering of overall storage space available, rather than a storage integrity issue?

f) Union indicates at Exhibit D1, Tab 8, Page 1, that:

As an integrated storage and transmission system operator Union requires system integrity space to support the integrity of the system as a whole and provide the provision of service to all customers. It provides reserve capacity and allows for the operational balancing necessary to manage all of the services Union offers and ensures the integrity of Union's storage, transmission and distribution systems.

Since this supports all services including storage, please indicate how much of this integrity space has been allocated to non-utility storage. Explain.

Response:

a) There was no deliverability assigned to the integrity space in EBRO 499.

b)

i. The hysteresis included in the analysis of system integrity space has increased for all storage pools. It is not attributable to any individual storage pool.

ii. The updated hysteresis trends were identified in 2010.

iii. Changes incorporated into the system integrity space as a result of hysteresis are due to changes in the modeling assumptions, not due to storage development programs over the past 10 years.

c) As storage pools are filled, pools are shut-in for stabilization. Union estimates the hysteresis in each pool to determine the shut-in pressure required to ensure that the maximum allowable operating pressures are not exceeded. Following stabilization the actual hysteresis observed in the pools may vary from the estimated values used to shut-in the pools. The variance between the actual and estimated pressures may result in a shortfall. Empty system integrity space is required to manage this variance.

d)

i. Please refer to Exhibit D1, Tab 9, pp. 5 and 6.
ii. As noted at Exhibit D1, Tab 9, pp. 5 and 6, the 3.5 PJ of empty space is held to manage items such as:

1. Forecasted weather variances
2. Unaccounted-for-gas forecast variances
3. Storage pool hysteresis
4. OBA/LBA imbalances

The 3.5 PJ of storage space is not used to manage the timing of gas purchases.

e) The space reserved for system integrity is required to manage the variance between the predicted and actual hysteresis, not the total hysteresis. Because of the complexity and uncertainty associated with predicting hysteresis it is an operational risk which requires Union to support potential deliverability shortfalls as a provider of last resort. This is consistent with the other components making up system integrity space.

f) Union has allocated system integrity costs to the non-utility storage operation consistent with the Board-approved methodology.

Of the total 9.5 PJ of system integrity space, 0.2 PJ is allocated to short-term storage and 0.8 PJ is allocated to the non-utility storage operation. The short-term storage and non-utility system integrity costs are allocated to the Excess Utility Storage Space category in the cost allocation study.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit D1, Tab 9, Page 3, Table 1
Exhibit D3, Tab 2, Schedule 2

Union indicates in Exhibit D1, Tab 9, Page 3, Table 1 that the provision for UFG forecast variances is increasing from 1.8 PJ to 2.2 PJ (22% increase). Exhibit D3, Tab 2, Schedule 2 indicates a) that 2013 total forecasted throughput is comparable to the 3 year history, and b) the 3 year history clearly shows UFG volumes declining. Please explain why a 22% increase if system integrity space is required for UFG in light of relatively constant throughput and declining UFG ratios?

Response:

As stated in Exhibit D1, Tab 9, p. 4 of 6, line 7, system integrity space required for UFG is based on the variances between the actual and forecast UFG in any given monthly period. The variance depends on Union's ability to predict UFG. The uncertainty associated with predicting this value is used to determine system integrity space, not the total annual UFG trends.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex. B1/T5/p.8, lines 19-20:

"The operation of Union's Dawn-Parkway system continues to rely on firm deliveries to Union at Parkway."

a) Please explain fully how the operation of Union's Dawn-Parkway system relies on firm deliveries to Union at Parkway.

b) Please provide the volume of deliveries to Parkway that Union will require, by rate class, in each of 2012 and 2013.

c) Please quantify, by volume, the extent to which Union relies on Parkway deliveries to service in-franchise customers, and the extent to which Union relies on Parkway deliveries to serve ex-franchise customers.

d) What is the value to Union's customers, in each of 2012 and 2013, of the cost savings associated with Parkway obligated firm deliveries? Please disaggregate this value as between in-franchise and ex-franchise customers.

e) Please provide the volume of deliveries to Parkway that Union will require, by rate class, from or on behalf of customers located;

   i. West of Parkway but east of Dawn.

   ii. West of Dawn.

f) What is the current cost of transporting gas from Dawn to Parkway?

g) What is the current cost differential for buying gas delivered at Parkway versus buying gas delivered at Dawn?

Response:

a) Union relies on obligated Parkway deliveries (firm deliveries) in designing the Dawn-Parkway transmission system. These volumes, which are required to land at Parkway, plus the physical capacity of the Dawn-Parkway facilities, equal the total capacity of the Dawn-Parkway system. As a result of these deliveries the Dawn-Parkway transmission system is smaller than would otherwise be necessary to meet design day demand requirements. This translates into lower rates for all in-franchise customers in Union's system.

Winter 2013/2014 obligated (firm) deliveries at Parkway are 639,088 GJ/day. Removing the Parkway delivery obligation would result in increased transport requirements on the Dawn-Parkway system. A Dawn-Parkway transport increase of this size would require significant facilities expansion which would result in increased Dawn-Parkway costs to all customers.

b) Please see Attachment 1 for the volume of deliveries to Parkway for 2012 and 2013.

Union does not track deliveries by rate class for South Sales Service. Union's bundled direct purchase contracts are not rate class specific. These contracts have a mix of general service and contract rate accounts attached to each contract. As a result, Parkway deliveries by rate class are not available. However, Union can provide a breakout of bundled direct purchase contract deliveries between those that are 100% general service and those that have a contract rate account attached.

c) The volume of Parkway Obligated Deliveries for Winter 2012/13 and 2013/14 are shown below. Union relies upon these volumes to serve in-franchise customers on design day. Winter Parkway Obligated Deliveries (GJ/d)

Winter	Parkway Obligated Deliveries (GJ/d)
2012 / 2013	654,370
2013 / 2014	639,088

The Parkway Obligated Deliveries are made by in-franchise direct purchase customers and by Union on behalf of sales service customers to reduce transport requirements on the Dawn-Parkway system. Due to the net flow of gas from Dawn to Parkway, physical Obligated Delivery molecules are consumed downstream of Parkway by a combination of in-franchise and ex-franchise customers.

d) Removal of obligated deliveries at Parkway (639,088 GJ/day) would require the replacement volumes to be sourced from Dawn and shipped on the Dawn-Parkway system. The estimated capital cost of the expansion required to meet incremental Dawn send-out and Dawn-Parkway transport is between $250 million and $500 million. The removal of east end deliveries at Parkway will increase the volume of gas compressed at Parkway, and may impact the capacity of TCPL's system.

The facilities required vary depending on the amount of available capacity and future growth of the Dawn-Parkway demands. If sufficient Dawn-Parkway capacity were available to permanently eliminate the Parkway obligation there would be no change in rate base. In-franchise rates would, however, increase to reflect the increased use of the Dawn-Parkway system by in-franchise customers.

The approximate revenue requirement associated with expanding the Dawn-Parkway system is $30 million ($22 million to in-franchise rate classes) to $60 million ($33 million to in-franchise rate classes).

e) i. – ii. Please see the response to b) above.
Union does not track Parkway deliveries by customer location for South Sales Service, South Bundled –T, General Service and Unbundled services.

f) The cost to transport gas on the Union system from Dawn to Parkway is the M12 toll which can be found on Union's website at the following link:

http://www.uniongas.com/storagetransportation/services/currentm12ratesfuel.asp

The current 100% Load Factor rate is $.076 CDN/GJ/day plus the applicable fuel.

g) The cost differential between buying gas at Parkway vs. buying gas at Dawn changes constantly due to changing market conditions. Since the beginning of 2011 the average monthly differential has been as high as $0.14 US/mmbtu (Feb 2011). The current differential (monthly average up to April 10, 2012) is $0.06 US/mmbtu. All numbers are based on the daily Dawn-Parkway Physical Trading Spread as reported by NGX.

Schedule 1

Parkway Deliveries by Service Type/Rate Class

Line No.	Volumes in: GJ's	Annualized 2012 (a)	Annualized 2013 (b)	2012 East of Dawn (c)	2012 West of Dawn (d)	2013 East of Dawn (e)	2013 West of Dawn (f)
1	Total South Sales Service	32,954,215	33,042,355				
2	Total South Bundled T - General Service	27,834,900	26,911,085				
3	Total South Bundled T - Contract	35,301,517	34,230,771	20,642,387	14,659,130	19,757,061	14,473,710
4	Total T-1	78,449,085	79,179,450	27,707,880	50,741,205	28,326,920	50,852,530
5	Total T-3	11,708,835	11,708,835	11,708,835	-	11,708,835	-
6	Unbundled	5,589,245	5,592,530				
7	Total Parkway Deliveries	191,837,796	190,665,026	60,059,102	65,400,335	59,792,816	65,326,240

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit H3, T3, Schedule 1: Rate M4; Rate M5A; Rate M7.

a) Please confirm that Rate M4, M5A and M7 direct purchase customers must obligate to deliver gas to Union at points specified by Union.

b) On what basis does Union determine the points to which M4, M5A and M7 direct purchase customers will be obligated to deliver, and the quantities which these customers will be required to deliver to each such delivery point?

c) What is the process used to communicate to the customer their delivery point obligations? Is there any scope for input from the customer during that process?

d) What is the current annualized volume of gas obligated for delivery to Parkway for each of Union's M4, M5A and M7 customer classes?

e) How much of the volume provided in response to part d. is delivered by customers in each of Union's M4, M5A and M7 rate classes who are located;

   i. West of Parkway but East of Dawn?

   ii. West of Dawn?

Response:

a) Confirmed.

b) Union has policies that outline which points customers must obligate to deliver to and how the quantities are determined. Please see policies included in response to J.D-18-13-1b.

c) The procedures for determining a new customer's delivery obligations, or making changes to an existing customer's delivery point obligations is set out by policy #'s 05-DP-DCQN-008, 05-DP-DCQS-009 and 10-DP-DCQS-009. The policies are included as Attachments 1 – 3 and are also available for viewing on Union's website at www.uniongas.com.

   A customer's delivery point obligations are communicated as part of the contracting process whether it is a new contract or a renewal. A Union Gas Account Manager or Contract Service Representative would advise the potential or existing customer of the requirement for the delivery point obligation specific to the contract that is under consideration. In each case, the Obligated Delivery Point policy appropriate for the contract circumstance is applied and is not negotiable.

d) Union's bundled direct purchase contracts have a mix of M4, M5A, and M7 distribution accounts and general service accounts attached to each them. There is not necessarily a one-to-one relationship between a distribution contract and a bundled direct purchase contract. The DCQ policy treats contracts with an attached M4, M5A and M7 account the same. As a result, the answers provided below are for the group of direct purchase contracts with contract rate accounts attached.

Please see the response at Exhibit J.D-18-9-1 b), Attachment 1 Line 3.

e) i. – ii. Please see the response at Exhibit J.D-18-9-1 b).

POLICIES & GUIDELINES

Policy #: 05-DP-DCQN-008

Subject: Setting new and increasing or decreasing existing, Obligated Daily Contract Quantity (DCQ) - Union Gas North	**Effective**: **July 24, 2008**

Applies to:

All new or existing Bundled-T (BT) direct purchase customers in Union Gas's Northern and Eastern operations area. It excludes those situations where Union Gas's nominations to the customers are adjusted periodically during the term of the contract to reflect a planned zero Banked Gas Account (BGA) balance at the end of the contract year.

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a customer's Daily Contract Quantity (DCQ).

Background: *(Not to limit the applicability of the policy)*

The direct purchase contract identifies the obligated DCQ for the term of the contract. This policy addresses situations where either: a new contract requires a DCQ to be set; or a change in obligated DCQ is requested by a customer and/or their agent; or a change in obligated DCQ is required at the time of contract renewal or contract amendment.

Upstream Load Factor reflects the percent utilization of upstream assets contracted to serve a Union Gas Delivery Area. The load factor is determined by dividing the forecasted annual utilization of upstream assets for a delivery area by the annual contracted quantity for upstream assets to serve the Delivery Area. Currently the load factors in the Northern and Eastern operations area are 100%.

Policy:

When initiating a contract, the DCQ will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term. The DCQ for BT contracts is obligated.

Union Gas will determine the obligated DCQ based on the most recent 12 months of actual firm consumption of end use locations underlying the direct purchase contract / 365 days * Heat Value (GJ/m^3)/load factor. If the contract has a term greater than 12 months, the DCQ is calculated by dividing the historical consumption for the term of the contract by the number of days in the contract term. The consumption of general service end-use locations is weather normalized.

Setting the DCQ when initiating a new Direct Purchase contract

Non-telemetered General Service end-use locations served under Rate 01 and Rate 10 with new consumption	▪ End-use locations either transferring from Union Gas's sales service or transferring from an existing direct purchase contract will receive an allocation of Union Gas's Western upstream transportation arrangements.
Telemetered Contract end-use locations served under Rate 20 and Rate 100 with new consumption	▪ End-use locations either transferring from Union Gas's sales service or transferring from an existing direct purchase contract will receive an allocation of Union Gas's Western upstream transportation arrangements.

Increasing an existing Direct Purchase DCQ parameter

Non-telemetered General Service end-use locations served under Rate 01, and Rate 10	▪ Any DCQ increases: due to end-use locations transferring from Union Gas's sales service; or due to end-use locations transferring from an existing direct purchase contract; or due to consumption increases will receive an allocation of Union Gas's Western upstream transportation arrangements,
Telemetered Contract end-use locations served under Rate 20 and Rate 100.	▪ Any DCQ increases: due to end-use locations transferring from Union Gas's sales service; or due to end-use locations transferring from an existing direct purchase contract; or due to consumption increases will receive an allocation of Union Gas's Western upstream transportation arrangements.

Decreasing an existing Direct Purchase DCQ parameter

Non-telemetered General Service end-use locations served under Rate 01, Rate 10	▪ Any DCQ decreases: due to end-use locations transferring to Union Gas's sales service; or due to end-use locations transferring to an existing direct purchase contract; or due to consumption decreases will be managed by decreasing the Customer's Western DCQ.
Telemetered Contract end-use locations served under Rate 20 and Rate 100	▪ Any DCQ decreases: due to end-use locations transferring to Union Gas's sales service; or due to end-use locations transferring to an existing direct purchase contract; or due to consumption decreases will be managed by decreasing the Customer's Western DCQ.

Procedures

1) Union Gas will calculate or recalculate DCQ under the following circumstances:
   a. Upon contract renewal, or
   b. Upon the addition or deletion of end-use locations to/from the contract based on an effective date that is other than the contract renewal date. End-use locations may be added or deleted to the contract pursuant to the Gas Distribution Access Rule Electronic Business Transactions Standard. An amendment to the contract in this event is created at Union Gas's discretion.

2) For direct purchase contracts comprised of telemetered general service and contract rate end-use locations, the DCQ calculation at contract renewal, the calculation will be based on information available approximately 80 days prior to contract renewal. In addition:
   a. Union Gas will issue a Contract Parameters Report summarizing forecast consumption, changes in obligated DCQ, and corresponding changes in upstream transportation allocation consistent with the above policy approximately 70 days prior to the contract's renewal date.
   b. Customer may propose and Union Gas may accept an alternative forecast (with a resulting change in obligated DCQ) provided the contract holder provides justification acceptable to Union Gas for the increase or decrease - a forecast of expected consumption to support the requested obligated DCQ must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.
   c. Customer will sign back the Contract Parameters Report approximately 54 days prior to the contract's

renewal date.

3) Union Gas will issue a final Contract Parameters Report and contract amendment (reflecting obligated DCQ changes consistent with the above policy) approximately 35 days before the effective date of the amendment for customer signature.

4) Customer will sign and return the contract amendment to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract amendment and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with their respective schedules.

7) Customer will nominate deliveries to Union Gas reflecting the above contract amendment.

POLICIES & GUIDELINES

Policy #: 05-DP-DCQS-009

Subject:	**Effective**:
Setting new, and increasing or decreasing existing, Obligated Daily Contract Quantity (DCQ) - Union Gas South	**November 1, 2010**

Applies to:

All new or existing Bundled-T (BT), T-Service (T1/T3) and Unbundled (U2, U5, U7, U9) direct purchase customers in Union Gas's Southern operations area that are not eligible for Firm Billing Contract Demand. (Policy #10-DP-DCQS-009)

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a customer's Daily Contract Quantity (DCQ).

Background: *(Not to limit the applicability of the policy)*
The direct purchase contract identifies the obligated DCQ for the term of the contract. This policy addresses situations where: a new contract (location not previously served by Union) requires a DCQ to be set; or, a change in obligated DCQ is requested by an existing customer and/or their agent; or, a change in an existing obligated DCQ is required at the time of contract renewal or contract amendment.

Once a customer has received a Vertical Slice allocation, all future end use location transfers from Union Gas's sales service will result in an allocation of Vertical Slice.

A U2 customer is a customer, or an agent, who is authorized to serve residential and non-contract commercial and industrial end-users paying a Monthly Fixed Charge and Delivery Charge under Rate M1 or M2.

West of Dawn – Customer's end-use locations are served by Union Gas via the PanHandle 16 and 20 inch system and/or the Sarnia Industrial system.

East of Dawn – Customer's end-use locations are served by Union Gas via the Dawn to Trafalgar transmission system.

Parkway Call - Union Gas has the right to require Unbundled Customers to deliver 100% of their Parkway DCQ at Parkway for the number of days listed in Schedule 1 of their Contract. Except for the Parkway Call, the customer has no obligation to deliver any quantities on any day. Nominations to a secondary receipt point are interruptible.

Policy:

When initiating a contract, the DCQ will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term. The DCQ for BT, T1, and T3 contracts is obligated. The DCQ for unbundled contracts is not obligated but subject to a Parkway Call when requested by Union Gas.

DCQ (GJ/day) is equal to 12 months historical volumetric consumption at the end use locations underlying the direct purchase contract / 365 days * Heat Value (GJ/10^3m^3). If the contract has a term greater than 12 months, the DCQ is calculated by dividing the historical volumetric consumption for the term of the contract by the number of days in the contract term. The consumption of general service end-use locations is weather normalized.

Setting the DCQ when initiating a new Direct Purchase contract

Non-telemetered General Service end-use locations served under Rate M1 or M2 with new consumption	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any new contract with a DCQ less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9 with new consumption	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any new contract with a DCQ less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract, unless otherwise agreed to by the two contracting parties. ▪ New end-use locations, not previously served by Union Gas's sales service, will be allocated: • If located **East of Dawn,** the DCQ will be managed through Ontario deliveries made at Parkway. • If located **West of Dawn,** the DCQ will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option.
Increasing an existing Direct Purchase DCQ parameter	
Non-telemetered General Service end-use locations served under Rate M1 or M2	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any contract with a DCQ increase of less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract. ▪ Any DCQ increases due to consumption, for contracts that currently have Ontario deliveries, will be managed through Ontario deliveries at Parkway. ▪ Any DCQ increases due to consumption, for contracts that do not currently have Ontario deliveries, will be managed through an allocation of TCPL capacity, if available. If TCPL capacity is not available, or if the customer requests it, the DCQ increase will be managed though Ontario deliveries at Parkway.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any contract with a DCQ increase of less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract, unless otherwise agreed to by the two

	contracting customers. ▪ Any increases in DCQ due to consumption will first be applied at the Ontario Point(s) of Receipt last decreased, where it can be determined. The greatest DCQ at each Ontario Point of Receipt from previous contract amendments will be used as the basis to determine this. Any increase in excess of what was previously contracted will receive an allocation as follows: • If points of consumption are **East of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Parkway. • If points of consumption are **West of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option. • If points of consumption are **East and West of Dawn**, a review needs to be completed at the account level to determine which account had the increase and the policy can be applied appropriately as above. ▪ If the Ontario Point(s) of Receipt last decreased cannot be determined, the increase will be prorated between the Ontario Points of Receipt. ▪ New end-use locations that were not previously served by Union Gas's sales service that are being added to an existing Direct Purchase arrangement will receive an allocation as follows: • If located **East of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Parkway. • If located **West of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option.
Decreasing an existing Direct Purchase DCQ parameter	
Non-telemetered General Service end-use locations served under Rate M1 or M2	▪ DCQ decreases as a result of consumption will be managed by prorating the decrease over the Ontario Points of Receipt first. If the decrease is greater than the total of the Ontario Points of Receipt, the remaining decrease will be prorated over all the other current Points of Receipt. ▪ All other decreases to DCQ, including a transfer to Union Gas's sales service, will be prorated evenly across the contract's then current Points of Receipt and associated upstream arrangements will be reduced proportionately.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9	▪ DCQ decreases will be managed by first decreasing Ontario Points of Receipt. o Where the customer has multiple Ontario Points of Receipt, the decrease will be applied to the receipt points in the reverse order that they were increased since the initial contract; where contract history is available. o If the last point of receipt cannot be determined then the decrease will be prorated between the Ontario Points of Receipt. Reductions in upstream arrangements allocated/assigned by Union Gas to the customer will be adjusted accordingly. ▪ Once all of the Ontario Points of Receipt have been exhausted, upstream arrangements allocated/assigned by Union Gas to the customer will then be reduced

Procedures

1) Union Gas will calculate or recalculate DCQ under the following circumstances:
    a. Upon contract renewal, or
    b. Upon the addition or deletion of end-use locations to/from the contract based on an effective date that is other than the contract renewal date. End-use locations may be added or deleted to the contract pursuant to the Gas Distribution Access Rule Electronic Business Transactions Standard. An amendment to the contract in this event is created at Union Gas's discretion.

2) For direct purchase contracts comprised of telemetered general service and contract rate end-use locations, the DCQ calculation at contract renewal, will be based on information available approximately 80 days prior to contract renewal. In addition:
    a. Union Gas will issue a Contract Parameters Report summarizing forecast consumption, changes in obligated DCQ, and corresponding changes in upstream transportation allocation consistent with the above policy approximately 70 days prior to the contract's renewal date.
    b. Customer may propose and Union Gas may accept an alternative forecast (with a resulting change in obligated DCQ) provided the contract holder provides a justification acceptable to Union Gas for the increase or decrease - a forecast of expected consumption to support the requested obligated DCQ must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.
    c. If Customer's consumption is predominately in a single season, Union Gas will consider a seasonal DCQ where mutually agreed upon.
    d. Customer will sign back the Contract Parameters Report approximately 54 days prior to the contract's renewal date.

3) Union Gas will issue a final Contract Parameters Report and contract amendment (reflecting obligated DCQ changes consistent with the above policy, and the resulting balancing requirements) approximately 35 days before the effective date of the amendment for customer signature.

4) Customer will sign and return the contract amendment to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract amendment and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with schedule one of the contract.

7) Customer will nominate deliveries to Union Gas reflecting the above contract amendment.

POLICIES & GUIDELINES

Policy #: 10-DP-DCQS-009

Subject:	**Effective**:
Setting new, and increasing or decreasing existing Daily Contract Quantity (DCQ) or Parkway Call for customers that are eligible to choose the Firm Billing Contract Demand (FBCD).	April 21, 2010

Applies to:

All new or existing T1, T3 or U7 direct purchase customers that are eligible to choose for FBCD by having new or incremental loads greater than 1,200,000 m^3/day and that are directly connected to: i) the Dawn to Trafalgar transmission system in close proximity to Parkway; or ii) a third party pipeline.

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a T1/T3/U7 customer's Daily Contract Quantity (DCQ) and a U7 customer's Parkway Call.

Background: *(Not to limit the applicability of the policy)*

The direct purchase contract identifies the DCQ for the term of the contract. This policy addresses situations where either a new contract requires a DCQ to be set or a change in an existing DCQ is requested by a customer or their agent, or is required at the time of contract renewal or contract amendment. For a U7 customer, the DCQ is not obligated but the firm entitlement at Parkway is subject to call back at Parkway.

The Firm Operational Contract Demand (FOCD) is the maximum firm daily requirement of the end use facility (i.e. 24 hours x peak hour). This has traditionally been used for the billing of demand charges.

A FBCD is a billing parameter used to recover Union's facility and ongoing costs to serve the end use location over the term of the contract. The FBCD was developed to respond to the competitive pressure of physical by-pass. Pursuant to the Natural Gas Electricity Interface Review (NGEIR) Decision, the FBCD is provided, at the customer's option, as an alternative for the billing of demand charges. The FBCD lowers the customer's demand charge commitment over the term of the initial contract. The customer's actual daily firm consumption requirement is equal to 100% of the FOCD. Daily consumption volumes that fall between the FBCD parameter and the CD parameter are firm, and will be invoiced at the T1or U7 firm transportation Authorized Overrun Rate.

Customers initiating contracts after December 31, 2006, are eligible to choose the FBCD if new or incremental loads are greater than 1,200,000 m^3/day and are directly connected to: i) the Dawn to Trafalgar transmission system in close proximity to Parkway; or ii) a third party pipeline. If the customer does not meet these criteria, they would not be eligible for the FBCD option.
.
West of Dawn – customers' end use locations served by the PanHandle 16 and 20 inch lines as well as the Sarnia Industrial line.

East of Dawn – customers' end use locations served by the Dawn to Trafalgar transmission line.

Summary of DCQ Calculations

- For T1/T3 customers who are eligible for and have chosen the FBCD, the DCQ is calculated as 100% of their FOCD.
- For T1/T3 customers who are not eligible for and have not chosen the FBCD, the DCQ is equal to a minimum of 80% of the FOCD.
- For U7 customers who are eligible for and have chosen the FBCD, their Parkway Call is equal to 100 % of their FOCD or will deliver all of their firm entitlement at Parkway in the same hourly pattern as their plant is consuming.
- For U7 customers who are not eligible for and have not chosen the FBCD, their Parkway Call is equal to 80% of their FOCD or they will deliver all of their firm entitlement at Parkway in an amount equal to at least 80% of their hourly consumption.

Policy:

When initiating a contract, the DCQ and, if applicable, Parkway Call will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ and, if applicable, Parkway Call may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term.

Setting the DCQ for new Contract customers served under rates: T1 or T3 with new incremental consumption > 1,200,000 m^3/day.	New T1/T3 customers located **East of Dawn** a. Who are eligible and have chosen a FBCD: i) Will require obligated Ontario Deliveries at Parkway equal to 100% of their FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above that would sum to 100% of their FOCD. b. Who are not eligible or have not chosen the FBCD option: i) Will require obligated Ontario Deliveries at Parkway equal to at least 80% of their FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above that would sum to at least 80% of their Firm CD. New T1/T3 customers located **West of Dawn** i) Have an option to contract for Non-Obligated DCQ requirement at Dawn contingent on Union's facilities. Otherwise the DCQ will be an Obligated DCQ or a combination of Non-Obligated and Obligated DCQ.
Setting DCQ and Parkway Call for new Contract customers served under U7 rate with new incremental consumption > 1,200,000 m^3/day.	New U7 customers located **East of Dawn.** a. Who have chosen a FBCD: i) Will maintain arrangements sufficient to meet their Parkway Call provision equal to 100% of their FOCD; **OR** ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR** iii) Can elect any combination of options a(i) or a(ii) above b. Who are not eligible or have not chosen the FBCD option: i) Will maintain arrangements sufficient to meet their Parkway Call provision equal to at least 80% of their FOCD; **OR** ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption.; **OR** iii) Can elect any combination of options b(i) or b(ii) above New U7 customers located **West of Dawn** i) Have an option to contract for Non-Obligated DCQ requirement at Dawn, and no Parkway Call, contingent on Union's facilities.

Increase to DCQ for existing Contract customers served under rates T1 or T3 with a Firm Transportation Demand > 1,200,000 m^3/day.	T1/T3 customers located **East of Dawn** a. Who are eligible and have chosen a FBCD: i) The increase will be managed through additional obligated Ontario Deliveries at Parkway equal to 100% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their revised FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above that would sum to 100% of their revised FOCD. b. Who are not eligible or have not chosen the FBCD option: i) The increase will be managed through additional obligated Ontario Deliveries at Parkway equal to at least 80% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their revised FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above that would sum to at least 80% of their revised Firm CD. T1/T3 customers located **West of Dawn** i) Will have an option to contract for Non-Obligated DCQ requirement at Dawn contingent on Union's facilities. Otherwise the DCQ will be an Obligated DCQ or a combination of Non-Obligated and Obligated DCQ.
Increase in DCQ and Parkway Call for existing Contract customers served under U7 rate with a Firm a Transportation Demand > 1,200,000 m^3/day	U7 customers located **East of Dawn.** a. Who have chosen a FBCD: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to 100% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above b. Who have not chosen the FBCD option: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to at least 80% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above U7 customers located **West of Dawn** i) Have an option to contract for Non-Obligated DCQ requirement at Dawn, and no Parkway Call, contingent on Union's facilities.
Decrease to Obligated DCQ for existing Contract customers served under rates T1 or T3 with a Firm Transportation Demand > 1,200,000 m^3/day with decreased consumption.	T1/T3 customers located **East of Dawn** a. Who are eligible and have chosen a FBCD: i) The decrease will be managed through a reduction in obligated Ontario Deliveries at Parkway equal to 100% of the reduction in their FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their revised FOCD and assign the adjusted capacity to Union which will allow the customer to contract for non-obligated Ontario deliveries; **OR** iii) Can elect to retain any combination of options a.(i) or a.(ii) above

	that would sum to 100% of their revised FOCD. b. Who have not chosen the FBCD option: i) The decrease will be managed through a reduction in obligated Ontario Deliveries at Parkway equal to at least 80% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their revised Firm CD and assign the adjusted capacity to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect anya combination of options b.(i) or b.(ii) above that would sum to at least 80% of their revised Firm CD. T1/T3 customers located **West of Dawn** i) Will have an option to reduce Non-Obligated or Obligated DCQ requirement at Dawn to meet the revised Contracted Demand.
Decrease to DCQ and Parkway Call **for existing** Contract customers served under U7 rate with a Firm Transportation Demand > 1,200,000 m^3/day with decreased consumption	U7 customers located **East of Dawn.** a. Who are eligible and have chosen a FBCD: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to 100% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above b. Who have not chosen the FBCD option: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to at least 80% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above U7 customers located **West of Dawn** i) Do not have a Parkway Call.

Procedures

1) The DCQ and, if applicable, Parkway Call will be determined as outlined in the policy based on information available approximately 80 days prior to the effective date of the contract or contract renewal.

2) Customer may propose and Union Gas may accept an alternative consumption forecast (with a resulting change in DCQ and, if applicable, Parkway Call) provided the contract holder provides justification acceptable to Union Gas for the change. The forecast of expected consumption to support the requested DCQ and, if applicable, Parkway Call must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.

3) Union Gas will issue a contract or contract amendment (reflecting parameters consistent with the above policy, and the resulting balancing requirements) approximately 35 days before the effective date of the contract or contract amendment for customer signature. If applicable, an M12 contract for Dawn to Parkway transportation will also be issued to customer for signature.

4) Customer will sign and return the contract(s) or contract amendment(s) to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract(s) or contract amendment(s) and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with their respective schedules.

7) Customer will nominate deliveries to Union Gas reflecting the above contract(s) or contract amendment(s).

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit H3, T3, Schedule 2: Rate T1.

a) Please confirm that Union will continue to require T1 direct purchase customers to deliver gas to Union at delivery points specified by Union.

b) On what basis will Union determine the points to which T1 direct purchase customers will be obligated to deliver, and the and the quantities which these customers will be required to deliver to each such delivery point?

c) What process will be used to communicate to the customer their delivery point obligations? Is there any scope for input from the customer during that process?

d) What is the current annualized volume of gas obligated for delivery to Parkway for Union's T1 customer class?

e) What annualized volume of gas is expected to be obligated for delivery to Parkway for Union's T1 customer class in 2013 if Union's proposal to establish at T2 rate class is accepted?

f) How much of the volume provided in response to part d. is delivered by T1 customers who are located;

   i. West of Parkway but East of Dawn?

   ii. West of Dawn?

Response:

a) Confirmed.

b) Union has policies that outline which points T-1 customers must obligate to deliver to and how the quantities are determined. Please see policies included in response to J.D-18-13-1 b).

c) Please see the response at Exhibit J.D-18-9-2 c).

d) Please see the response at Exhibit J.D-18-9-1 b), Attachment 1, Line 4

e) The annualized volume of gas expected to be obligated for delivery to Parkway for Union's T1 customer class in 2013 if Union's T2 proposal is accepted is 14,925,215 GJ.

f) Please see the response at Exhibit J.D-18-9-1 b), Attachment 1, Line 4.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex.H3/T3/S2: Rate T2.

The proposed T2 rate schedule provides (item 3) that direct purchase customers "*with incremental daily firm demand requirements in excess of 1.2 million m3/day may be entitled to non-obligated deliveries*". [emphasis added] The proposed rate schedule goes on to specify that, unless authorized by Union, direct purchase customers must obligate to deliver at points specified by Union.

a) Please explain what "non-obligated deliveries" are.

b) Please explain the basis on which T2 direct purchase customers would be entitled to non-obligated deliveries, and the rationale for that basis.

c) For T2 direct purchase customers other than those entitled to non-obligated deliveries, on what basis will Union determine the points to which such customers will be obligated to deliver, and the quantities which these customers will be required to deliver to each such delivery point?

d) What process will be used to communicate to the customer their delivery point options/obligations? Is there any scope for input from the customer during that process?

e) What annualized volume of gas is expected to be obligated for delivery to Parkway in 2013 for Union's proposed T2 direct purchase customer class?

   i. How much of the volume provided in response to part e. is expected to be delivered by customers in Union's proposed T2 rate class who are located;

   ii. West of Parkway but East of Dawn?

   iii. West of Dawn?

Response:

a) The general terms and conditions definition of "Non-Obligated" is any quantities of gas that are not committed to be delivered by Customer on a Firm basis and which Union will receive on a Firm basis when delivered by Customer. The non-obligated delivery provision has been incorporated into semi-bundled contracts that meet the specifications outlined in Policy # 10-

DP-DCQS-009. Please see Exhibit J.D-18-9-2, Attachment 3.

b) To be eligible for non-obligated deliveries, T2 customers must meet the criteria set out in Policy # 10-DP-DCQS-009. Please see Exhibit J.D-18-9-2, Attachment 3.

c) Please see the response at Exhibit J.D-18-9-2 c).

d) Please see the response at Exhibit J.D-18-9-2 c).

e) i. The annualized volume of gas expected to be obligated for delivery at Parkway in 2013 for Union's proposed T2 customer class is 64,254,235 GJ.

ii. East of Dawn – 18,189,045 GJ.

iii. West of Dawn – 46,065,190 GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit B1, T9, page 6, pp. 3–4:

Union expects excess capacity on the Dawn-Parkway system for the winter of 2012/2013 and the winter 2013/2014.

a) Please explain the extent to which the expected excess Dawn-Parkway capacity mitigates Union's need to rely on Parkway deliveries.

b) Please explain how Union has/will adjust Parkway delivery commitments for its customers as result of the expected excess Dawn-Parkway capacity.

Response:

a) For the winter of 2012/2013, excess Dawn-Parkway capacity does not mitigate Union's need to rely on Parkway deliveries. The surplus Dawn-Parkway capacity mitigates Union's requirement for a Winter Peaking Service at Parkway for winter 2012/2013. The effect of not requiring a Winter Peaking Service reduces Union's cost which translates into reduced rates for ratepayers.

b) For the winter of 2012/2013, the surplus capacity has been allocated to reducing Union's Winter Peaking Service requirements at Parkway. There will be no impact on customer's contractual obligated delivery commitments.

   Union continues in its efforts to re-market any excess Dawn to Parkway capacity available.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit G3, T1, Schedule 1 page 14:

Union describes how it allocates Transmission – Dawn Station – Demand costs. In-franchise customers in the South receive a credit for firm deliveries at Parkway.

a) Please describe the rationale for the credit referenced.

b) Please detail how the credit is determined and allocated to customers.

Response:

a) The rationale for the Union South in-franchise credit for firm deliveries at Parkway is described at Exhibit J.G-1-7-1.

b) The credit is the forecasted amount of Parkway firm deliveries made by in-franchise direct purchase customers and by Union on behalf of sales service customers. The Parkway firm deliveries are used to meet in-franchise demands at the transmission laterals west of Parkway. As a result, the demands required to be served from Dawn are reduced, which decreases the transmission compression horsepower requirements at Dawn. Please see Attachment 1 for the Dawn Compression Allocation Detail Report. The credit is shown on Line 2 of Attachment 1.

Dawn Compression Allocation Detail Report

Line No.	Particulars	Total	Gen. Service Small Volume M1	Gen. Service Large Volume M2	Firm Contract M4	Interruptible Contract-Firm M5	Interruptible Contract-Interruptible M5	Special Large Volume Contract - Firm M7	Special Large Volume Contract - Interruptible M7	Large Wholesale Service M9	Small Wholesale Service M10	Storage & Transportation Service - Firm T1	Storage & Transportation Service - Interruptible T1	Wholesale Storage & Transportation Service T3
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Dawn Compression Allocator													
1	Design Day Demands from Dawn (10^3m^3/day)	167,112						43,115						
2	Parkway Firm Deliveries (10^3m^3/day)	(16,929)						(16,929)						
3	Dawn Compression (10^3m^3/day)	150,183						26,186						
4	OSE load not requiring Dawn Compression	(1,100)						(192)						
5	Dawn Compression excl. OSE (10^3m^3/day)	149,083						25,994						
6	Infranchise Peak Day Demand (10^3m^3/day)	43,624	22,124	7,443	2,162	20	0	997	0	356	11	7,999	0	2,511
7	North allocated on XSPK&AVG													
8	Infranchise Dawn Compression Allocation (10^3m^3/day)	32,899	13,183	4,435	1,288	12	0	594	0	212	7	4,766	0	1,496
9	DAWNCOMP (10^3m^3/day)	149,083	13,183	4,435	1,288	12	0	594	0	212	7	4,766	0	1,496

Dawn Compression Allocation Detail Report

Line No.	Particulars	Total	Dawn-Trafalgar Transport Service M12	Small Volume General Firm Service R01	Large Volume General Firm Service R10	Medium Volume Firm Service R20	Large Volume High Load Factor Firm Service R100	Large Volume Interruptible Service R25
		(a)	(n)	(o)	(p)	(q)	(r)	(s)
	Dawn Compression Allocator							
1	Design Day Demands from Dawn (10^3m^3/day)	167,112	117,041			6,956		
2	Parkway Firm Deliveries (10^3m^3/day)	(16,929)	0			0		
3	Dawn Compression (10^3m^3/day)	150,183	117,041			6,956		
4	OSE load not requiring Dawn Compression	(1,100)	(857)			(51)		
5	Dawn Compression excl. OSE (10^3m^3/day)	149,083	116,184			6,905		
6	Infranchise Peak Day Demand (10^3m^3/day)	43,624	0					
7	North allocated on XSPK&AVG			6,589	1,744	459	32	0
8	Infranchise Dawn Compression Allocation (10^3m^3/day)	32,899	0	5,156	1,365	359	25	0
9	DAWNCOMP (10^3m^3/day)	149,083	116,184	5,156	1,365	359	25	0

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex. B1/T9/p.9, line 6 *et seq.*

a) Please explain what the "Parkway call" is.

b) What is the difference, in intent and effect, between the "Parkway call" and Parkway firm delivery obligations.

Response:

a) The "Parkway call" is the commitment made by direct purchase customers contracting for its unbundled service as approved in RP-1999-0017. These customers have an obligation to deliver at Parkway when "called" by Union. Currently, Union can call these customers up to 22 days during the year when required to deliver required volumes on the Dawn to Parkway system.

b) The firm delivery obligations at Parkway is a 365 day delivery requirement. The "Parkway call" is on obligations to deliver volumes to Parkway only when requested by Union, up to 22 days during the year.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit B1, Tab 5, Page 8
Exhibit A2, Tab 1, Schedule 1, Page 12

APPrO wishes to better understand the impact of obligated deliveries:

a) Please provide the annual volume of obligated deliveries that Union has relied on arriving at Parkway commencing 2007 through to and including 2013.

b) Please provide Union's policy related to obligated deliveries for new and existing direct purchase customers arranging their own gas supply.

c) At Exhibit A2, Tab 1, Schedule 1, Page 12, Union indicates that it is forecasting cumulative surplus capacity as follows (GJ/d):

	2013	**2014-2018** (at Risk)
Dawn-Kirkwall	978,386	1,283,523
Dawn-Parkway	67,000	576,973

Please confirm that these volumes are for each of the full physical paths between Dawn and Kirkwall as well as between Dawn and Parkway.

d) In the event that surplus capacity exists as shown to Parkway, please confirm that the dependence on obligated deliveries can be reduced by the amount of the surplus capacity.

e) Please confirm that if a customer situated in either Windsor or Sarnia were to source its gas at Dawn, that Union would not require the use of its Dawn-Trafalgar transmission system to deliver the gas to the customer. If not confirmed, please explain.

f) In light of the continued evolution of the natural gas industry from the mid-1980's when direct purchase customers were required to take assignment of the long term, longhaul TCPL contracts, to the current day market where a vibrant, liquid market hub exists at Dawn and is the 'go to market centre' for gas consumers in Ontario, is it time to re-evaluate the Parkway obligation? Please explain.

Response:

a) Please see the response at Exhibit J.B-1-7-5 a) for obligated delivery volumes between 2007 and 2011.

Please see the response at Exhibit J.D-18-9-1 c) for obligated deliveries volumes forecast for 2012 and 2013.

b) Please see Attachments 1 – 4. Union's policies related to the setting of the DCQ can be found on the Union Gas website at the following links:

Union South:

http://www.uniongas.com/aboutus/policies/pdf/DCQ_South%20Over.pdf

http://www.uniongas.com/aboutus/policies/pdf/DCQ_South.pdf

http://www.uniongas.com/aboutus/policies/pdf/Lessthan300GJ.pdf

Union North:

http://www.uniongas.com/aboutus/policies/pdf/DCQ_North.pdf

c) Confirmed

d) Please see the response at Exhibit J.D-18-9-5 a) and 5 b).

e) Customers located in Windsor are served by Union via the Panhandle 16 and 20 inch lines while the Sarnia Industrial system serves customers located in Sarnia. The Dawn-Parkway transmission system is not required to deliver gas to these customers.

f) The Parkway obligation is a replacement for Union building and operating physical infrastructure and therefore is still required. Should a change to this requirement be contemplated, Union would need to allocate the cost of the physical facilities required to the in franchise customers.

Customers have multiple options today to meet their obligations at Parkway, including but not limited to M12 Dawn to Parkway transportation capacity. Some customers have taken M12 capacity to eliminate their Parkway obligation.

POLICIES & GUIDELINES

Policy #: 10-DP-DCQS-009

Subject:	**Effective**:
Setting new, and increasing or decreasing existing Daily Contract Quantity (DCQ) or Parkway Call for customers that are eligible to choose the Firm Billing Contract Demand (FBCD).	April 21, 2010

Applies to:

All new or existing T1, T3 or U7 direct purchase customers that are eligible to choose for FBCD by having new or incremental loads greater than 1,200,000 m^3/day and that are directly connected to: i) the Dawn to Trafalgar transmission system in close proximity to Parkway; or ii) a third party pipeline.

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a T1/T3/U7 customer's Daily Contract Quantity (DCQ) and a U7 customer's Parkway Call.

Background: *(Not to limit the applicability of the policy)*

The direct purchase contract identifies the DCQ for the term of the contract. This policy addresses situations where either a new contract requires a DCQ to be set or a change in an existing DCQ is requested by a customer or their agent, or is required at the time of contract renewal or contract amendment. For a U7 customer, the DCQ is not obligated but the firm entitlement at Parkway is subject to call back at Parkway.

The Firm Operational Contract Demand (FOCD) is the maximum firm daily requirement of the end use facility (i.e. 24 hours x peak hour). This has traditionally been used for the billing of demand charges.

A FBCD is a billing parameter used to recover Union's facility and ongoing costs to serve the end use location over the term of the contract. The FBCD was developed to respond to the competitive pressure of physical by-pass. Pursuant to the Natural Gas Electricity Interface Review (NGEIR) Decision, the FBCD is provided, at the customer's option, as an alternative for the billing of demand charges. The FBCD lowers the customer's demand charge commitment over the term of the initial contract. The customer's actual daily firm consumption requirement is equal to 100% of the FOCD. Daily consumption volumes that fall between the FBCD parameter and the CD parameter are firm, and will be invoiced at the T1or U7 firm transportation Authorized Overrun Rate.

Customers initiating contracts after December 31, 2006, are eligible to choose the FBCD if new or incremental loads are greater than 1,200,000 m^3/day and are directly connected to: i) the Dawn to Trafalgar transmission system in close proximity to Parkway; or ii) a third party pipeline. If the customer does not meet these criteria, they would not be eligible for the FBCD option.
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West of Dawn – customers' end use locations served by the PanHandle 16 and 20 inch lines as well as the Sarnia Industrial line.

East of Dawn – customers' end use locations served by the Dawn to Trafalgar transmission line.

Summary of DCQ Calculations
- For T1/T3 customers who are eligible for and have chosen the FBCD, the DCQ is calculated as 100% of their FOCD.
- For T1/T3 customers who are not eligible for and have not chosen the FBCD, the DCQ is equal to a minimum of 80% of the FOCD.
- For U7 customers who are eligible for and have chosen the FBCD, their Parkway Call is equal to 100 % of their FOCD or will deliver all of their firm entitlement at Parkway in the same hourly pattern as their plant is consuming.
- For U7 customers who are not eligible for and have not chosen the FBCD, their Parkway Call is equal to 80% of their FOCD or they will deliver all of their firm entitlement at Parkway in an amount equal to at least 80% of their hourly consumption.

Policy:

When initiating a contract, the DCQ and, if applicable, Parkway Call will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ and, if applicable, Parkway Call may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term.

Setting the DCQ for new Contract customers served under rates: T1 or T3 with new incremental consumption > 1,200,000 m^3/day.

New T1/T3 customers located **East of Dawn**

a. Who are eligible and have chosen a FBCD:
   i) Will require obligated Ontario Deliveries at Parkway equal to 100% of their FOCD; **OR**
   ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR**
   iii) Can elect any combination of options a.(i) or a.(ii) above that would sum to 100% of their FOCD.

b. Who are not eligible or have not chosen the FBCD option:
   i) Will require obligated Ontario Deliveries at Parkway equal to at least 80% of their FOCD; **OR**
   ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR**
   iii) Can elect any combination of options b.(i) or b.(ii) above that would sum to at least 80% of their Firm CD.

New T1/T3 customers located **West of Dawn**

   i) Have an option to contract for Non-Obligated DCQ requirement at Dawn contingent on Union's facilities. Otherwise the DCQ will be an Obligated DCQ or a combination of Non-Obligated and Obligated DCQ.

Setting DCQ and Parkway Call for new Contract customers served under U7 rate with new incremental consumption > 1,200,000 m^3/day.

New U7 customers located **East of Dawn.**

a. Who have chosen a FBCD:
   i) Will maintain arrangements sufficient to meet their Parkway Call provision equal to 100% of their FOCD; **OR**
   ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR**
   iii) Can elect any combination of options a(i) or a(ii) above

b. Who are not eligible or have not chosen the FBCD option:
   i) Will maintain arrangements sufficient to meet their Parkway Call provision equal to at least 80% of their FOCD; **OR**
   ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption.; **OR**
   iii) Can elect any combination of options b(i) or b(ii) above

New U7 customers located **West of Dawn**

   i) Have an option to contract for Non-Obligated DCQ requirement at Dawn, and no Parkway Call, contingent on Union's facilities.

Increase to DCQ for existing Contract customers served under rates T1 or T3 with a Firm Transportation Demand > 1,200,000 m^3/day.	T1/T3 customers located **East of Dawn** a. Who are eligible and have chosen a FBCD: i) The increase will be managed through additional obligated Ontario Deliveries at Parkway equal to 100% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their revised FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above that would sum to 100% of their revised FOCD. b. Who are not eligible or have not chosen the FBCD option: i) The increase will be managed through additional obligated Ontario Deliveries at Parkway equal to at least 80% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their revised FOCD and assign such to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above that would sum to at least 80% of their revised Firm CD. T1/T3 customers located **West of Dawn** i) Will have an option to contract for Non-Obligated DCQ requirement at Dawn contingent on Union's facilities. Otherwise the DCQ will be an Obligated DCQ or a combination of Non-Obligated and Obligated DCQ.
Increase in DCQ and Parkway Call for existing Contract customers served under U7 rate with a Firm a Transportation Demand > 1,200,000 m^3/day	U7 customers located **East of Dawn.** a. Who have chosen a FBCD: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to 100% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above b. Who have not chosen the FBCD option: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to at least 80% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above U7 customers located **West of Dawn** i) Have an option to contract for Non-Obligated DCQ requirement at Dawn, and no Parkway Call, contingent on Union's facilities.
Decrease to Obligated DCQ for existing Contract customers served under rates T1 or T3 with a Firm Transportation Demand > 1,200,000 m^3/day with decreased consumption.	T1/T3 customers located **East of Dawn** a. Who are eligible and have chosen a FBCD: i) The decrease will be managed through a reduction in obligated Ontario Deliveries at Parkway equal to 100% of the reduction in their FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to 100% of their revised FOCD and assign the adjusted capacity to Union which will allow the customer to contract for non-obligated Ontario deliveries; **OR** iii) Can elect to retain any combination of options a.(i) or a.(ii) above

	that would sum to 100% of their revised FOCD. b. Who have not chosen the FBCD option: i) The decrease will be managed through a reduction in obligated Ontario Deliveries at Parkway equal to at least 80% of their revised FOCD; **OR** ii) Will contract for M12 Dawn to Parkway transportation equal to at least 80% of their revised Firm CD and assign the adjusted capacity to Union which will allow the customer to contract for non-obligated Ontario deliveries at Dawn; **OR** iii) Can elect anya combination of options b.(i) or b.(ii) above that would sum to at least 80% of their revised Firm CD. T1/T3 customers located **West of Dawn** i) Will have an option to reduce Non-Obligated or Obligated DCQ requirement at Dawn to meet the revised Contracted Demand.
Decrease to DCQ and Parkway Call **for existing** Contract customers served under U7 rate with a Firm Transportation Demand > 1,200,000 m^3/day with decreased consumption	U7 customers located **East of Dawn.** a. Who are eligible and have chosen a FBCD: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to 100% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in the same hourly pattern as their plant is consuming; **OR** iii) Can elect any combination of options a.(i) or a.(ii) above b. Who have not chosen the FBCD option: i) Will maintain arrangements sufficient to meet their Parkway Call Back provision equal to at least 80% of their revised FOCD; **OR** ii) Will deliver their supply at Parkway in an amount equal to at least 80% of their hourly consumption; **OR** iii) Can elect any combination of options b.(i) or b.(ii) above U7 customers located **West of Dawn** i) Do not have a Parkway Call.

Procedures

1) The DCQ and, if applicable, Parkway Call will be determined as outlined in the policy based on information available approximately 80 days prior to the effective date of the contract or contract renewal.

2) Customer may propose and Union Gas may accept an alternative consumption forecast (with a resulting change in DCQ and, if applicable, Parkway Call) provided the contract holder provides justification acceptable to Union Gas for the change. The forecast of expected consumption to support the requested DCQ and, if applicable, Parkway Call must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.

3) Union Gas will issue a contract or contract amendment (reflecting parameters consistent with the above policy, and the resulting balancing requirements) approximately 35 days before the effective date of the contract or contract amendment for customer signature. If applicable, an M12 contract for Dawn to Parkway transportation will also be issued to customer for signature.

4) Customer will sign and return the contract(s) or contract amendment(s) to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract(s) or contract amendment(s) and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with their respective schedules.

7) Customer will nominate deliveries to Union Gas reflecting the above contract(s) or contract amendment(s).

POLICIES & GUIDELINES

Policy #: 05-DP-DCQS-009

Subject: Setting new, and increasing or decreasing existing, Obligated Daily Contract Quantity (DCQ) - Union Gas South	**Effective**: **November 1, 2010**

Applies to:

All new or existing Bundled-T (BT), T-Service (T1/T3) and Unbundled (U2, U5, U7, U9) direct purchase customers in Union Gas's Southern operations area that are not eligible for Firm Billing Contract Demand. (Policy #10-DP-DCQS-009)

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a customer's Daily Contract Quantity (DCQ).

Background: *(Not to limit the applicability of the policy)*
The direct purchase contract identifies the obligated DCQ for the term of the contract. This policy addresses situations where: a new contract (location not previously served by Union) requires a DCQ to be set; or, a change in obligated DCQ is requested by an existing customer and/or their agent; or, a change in an existing obligated DCQ is required at the time of contract renewal or contract amendment.

Once a customer has received a Vertical Slice allocation, all future end use location transfers from Union Gas's sales service will result in an allocation of Vertical Slice.

A U2 customer is a customer, or an agent, who is authorized to serve residential and non-contract commercial and industrial end-users paying a Monthly Fixed Charge and Delivery Charge under Rate M1 or M2.

West of Dawn – Customer's end-use locations are served by Union Gas via the PanHandle 16 and 20 inch system and/or the Sarnia Industrial system.

East of Dawn – Customer's end-use locations are served by Union Gas via the Dawn to Trafalgar transmission system.

Parkway Call - Union Gas has the right to require Unbundled Customers to deliver 100% of their Parkway DCQ at Parkway for the number of days listed in Schedule 1 of their Contract. Except for the Parkway Call, the customer has no obligation to deliver any quantities on any day. Nominations to a secondary receipt point are interruptible.

Policy:

When initiating a contract, the DCQ will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term. The DCQ for BT, T1, and T3 contracts is obligated. The DCQ for unbundled contracts is not obligated but subject to a Parkway Call when requested by Union Gas.

DCQ (GJ/day) is equal to 12 months historical volumetric consumption at the end use locations underlying the direct purchase contract / 365 days * Heat Value (GJ/10^3m^3). If the contract has a term greater than 12 months, the DCQ is calculated by dividing the historical volumetric consumption for the term of the contract by the number of days in the contract term. The consumption of general service end-use locations is weather normalized.

Setting the DCQ when initiating a new Direct Purchase contract

Non-telemetered General Service end-use locations served under Rate M1 or M2 with new consumption	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any new contract with a DCQ less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9 with new consumption	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any new contract with a DCQ less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract, unless otherwise agreed to by the two contracting parties. ▪ New end-use locations, not previously served by Union Gas's sales service, will be allocated: • If located **East of Dawn,** the DCQ will be managed through Ontario deliveries made at Parkway. • If located **West of Dawn,** the DCQ will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option.
Increasing an existing Direct Purchase DCQ parameter	
Non-telemetered General Service end-use locations served under Rate M1 or M2	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any contract with a DCQ increase of less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract. ▪ Any DCQ increases due to consumption, for contracts that currently have Ontario deliveries, will be managed through Ontario deliveries at Parkway. ▪ Any DCQ increases due to consumption, for contracts that do not currently have Ontario deliveries, will be managed through an allocation of TCPL capacity, if available. If TCPL capacity is not available, or if the customer requests it, the DCQ increase will be managed though Ontario deliveries at Parkway.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9	▪ End-use locations transferring from Union Gas's sales service will receive an allocation of Union Gas's upstream transportation arrangements as defined in Union Gas's Vertical Slice Policy (Policy #03-DP-VS-002). Any contract with a DCQ increase of less than 300 GJ per day will be managed pursuant to Union Gas's < 300 GJ policy (Policy #03-DP-VS-003). ▪ End-use locations transferring from an existing direct purchase contract will bring a prorata allocation of the upstream capacity used to serve them on the originating contract, unless otherwise agreed to by the two

	contracting customers. ▪ Any increases in DCQ due to consumption will first be applied at the Ontario Point(s) of Receipt last decreased, where it can be determined. The greatest DCQ at each Ontario Point of Receipt from previous contract amendments will be used as the basis to determine this. Any increase in excess of what was previously contracted will receive an allocation as follows: • If points of consumption are **East of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Parkway. • If points of consumption are **West of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option. • If points of consumption are **East and West of Dawn**, a review needs to be completed at the account level to determine which account had the increase and the policy can be applied appropriately as above. ▪ If the Ontario Point(s) of Receipt last decreased cannot be determined, the increase will be prorated between the Ontario Points of Receipt. ▪ New end-use locations that were not previously served by Union Gas's sales service that are being added to an existing Direct Purchase arrangement will receive an allocation as follows: • If located **East of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Parkway. • If located **West of Dawn,** the DCQ increase will be managed through Ontario deliveries made at Dawn or Parkway at the customer's option.
Decreasing an existing Direct Purchase DCQ parameter	
Non-telemetered General Service end-use locations served under Rate M1 or M2	▪ DCQ decreases as a result of consumption will be managed by prorating the decrease over the Ontario Points of Receipt first. If the decrease is greater than the total of the Ontario Points of Receipt, the remaining decrease will be prorated over all the other current Points of Receipt. ▪ All other decreases to DCQ, including a transfer to Union Gas's sales service, will be prorated evenly across the contract's then current Points of Receipt and associated upstream arrangements will be reduced proportionately.
Telemetered General Service (M2) and Contract end-use locations served under rates: M4, M5, M7, M9, T1, T3, U5, U7, or U9	▪ DCQ decreases will be managed by first decreasing Ontario Points of Receipt. o Where the customer has multiple Ontario Points of Receipt, the decrease will be applied to the receipt points in the reverse order that they were increased since the initial contract; where contract history is available. o If the last point of receipt cannot be determined then the decrease will be prorated between the Ontario Points of Receipt. Reductions in upstream arrangements allocated/assigned by Union Gas to the customer will be adjusted accordingly. ▪ Once all of the Ontario Points of Receipt have been exhausted, upstream arrangements allocated/assigned by Union Gas to the customer will then be reduced

Procedures

1) Union Gas will calculate or recalculate DCQ under the following circumstances:
   a. Upon contract renewal, or
   b. Upon the addition or deletion of end-use locations to/from the contract based on an effective date that is other than the contract renewal date. End-use locations may be added or deleted to the contract pursuant to the Gas Distribution Access Rule Electronic Business Transactions Standard. An amendment to the contract in this event is created at Union Gas's discretion.

2) For direct purchase contracts comprised of telemetered general service and contract rate end-use locations, the DCQ calculation at contract renewal, will be based on information available approximately 80 days prior to contract renewal. In addition:
   a. Union Gas will issue a Contract Parameters Report summarizing forecast consumption, changes in obligated DCQ, and corresponding changes in upstream transportation allocation consistent with the above policy approximately 70 days prior to the contract's renewal date.
   b. Customer may propose and Union Gas may accept an alternative forecast (with a resulting change in obligated DCQ) provided the contract holder provides a justification acceptable to Union Gas for the increase or decrease - a forecast of expected consumption to support the requested obligated DCQ must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.
   c. If Customer's consumption is predominately in a single season, Union Gas will consider a seasonal DCQ where mutually agreed upon.
   d. Customer will sign back the Contract Parameters Report approximately 54 days prior to the contract's renewal date.

3) Union Gas will issue a final Contract Parameters Report and contract amendment (reflecting obligated DCQ changes consistent with the above policy, and the resulting balancing requirements) approximately 35 days before the effective date of the amendment for customer signature.

4) Customer will sign and return the contract amendment to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract amendment and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with schedule one of the contract.

7) Customer will nominate deliveries to Union Gas reflecting the above contract amendment.

POLICIES & GUIDELINES

Policy #: 03-DP-VS-003

Subject:	**Effective:**
Daily Contract Quantity (DCQ) increases of less than 300 GJ per day	November 2011

Applies to:
South Direct Purchase customers who have not been previously vertically sliced and have not accumulated an annual DCQ increase, resulting from addition of end use locations served under Union Gas's sales service, of at least 300 GJ/day.

Purpose:

To simplify the administration for both customer and Union Gas for minor DCQ increases.

Background: *(Not to limit the applicability of the policy)*

Note: Direct purchase customers and/or the direct purchase customers' appointed agents are jointly referred to as 'customers'.

The vertical slice methodology allocates upstream transportation capacity to customers moving from sales service to direct purchase in the same proportion that it exists in Union Gas's sales service upstream transportation portfolio. In Union Gas's vertical slice hearing (EB-2001-0441), Union Gas agreed to provide a mechanism to allocate100% TCPL capacity, if available, as per the previous Board approved allocation methodology to maintain simplicity for very small customers. The agreed to threshold of 300 GJ/day was established and subsequently implemented.

The following guidelines will be used to determine if the requested DCQ increase is deemed to fall under the 300 GJ threshold:

a. If any direct purchase contract held by the customer has previously been allocated vertical slice then all future DCQ increases resulting from additions from sales service will be allocated vertical slice.
b. If the requested increase causes the accumulated increases since the preceding April 1 to exceed 300 GJ then the requested DCQ increase, and all future increases, will be allocated vertical slice.

Note that the customer can choose to receive an allocation of Union Gas's vertical slice for DCQ increases instead of TCPL capacity (even if the DCQ increase is deemed to fall under the 300 GJ threshold).

Policy:

- When Union Gas has TCPL capacity available in the south sales service portfolio, it will be allocated to applicable customers. Customers may choose to receive an allocation of Union Gas's vertical slice.
- When Union Gas's TCPL capacity in the South sales service portfolio is depleted beyond a minimum operating level, it will temporarily cease allocation of 100% TCPL capacity. Customers will then have the following choices:
    - Remain on sales service and be placed in a queue until TCPL capacity is made available; or
    - Receive an allocation of Union Gas's vertical slice (Policy #03-DP-VS-002).

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Procedures

1. A sales service customer requests a direct purchase contract with a DCQ less than 300 GJ/day (per the guidelines noted above); or, an existing direct purchase customer requests a contract amendment/renewal to reflect an increase in DCQ resulting from the addition of end use locations previously served under Union's sales service that is less than 300 GJ/day (per the guidelines noted above).

2. If TCPL capacity is available then the increase in DCQ will be reflected as Western on the Contract Parameter Report and in the DCQ section of Schedule 1 of the direct purchase contract.

3. If TCPL capacity is not available then the customer will either:
   a. Decide to delay their change to a direct purchase contract and leave the applicable end use locations on sales service, in which case the customer must:
      i. Execute the transaction required to terminate any pending enrolments, if applicable; and
      ii. Optionally elect to be added to a queue until Western TCPL capacity is made available
   b. Decide to receive the vertical slice per the vertical slice procedure (Policy #03-DP-VS-002).

4. The customer will nominate supply per the nomination deadlines outlined in the contract. Customer must identify the contract SA# when nominating the supply. Further, customer must identify the supplier if customer had not previously done so.

5. Union Gas will confirm/schedule the nomination as outlined in the contract.

6. Gas will arrive as nominated and will be reflected in the Banked Gas Account through the receipts column of the DP Status Report or the storage account for a U2 customer.

Policy #: 05-DP-DCQN-008

POLICIES & GUIDELINES

Subject:	**Effective:**
Setting new and increasing or decreasing existing, Obligated Daily Contract Quantity (DCQ) - Union Gas North	**July 24, 2008**

Applies to:

All new or existing Bundled-T (BT) direct purchase customers in Union Gas's Northern and Eastern operations area. It excludes those situations where Union Gas's nominations to the customers are adjusted periodically during the term of the contract to reflect a planned zero Banked Gas Account (BGA) balance at the end of the contract year.

Purpose:

This policy will ensure consistent and fair treatment for setting and changing (either increases or decreases) a customer's Daily Contract Quantity (DCQ).

Background: *(Not to limit the applicability of the policy)*

The direct purchase contract identifies the obligated DCQ for the term of the contract. This policy addresses situations where either: a new contract requires a DCQ to be set; or a change in obligated DCQ is requested by a customer and/or their agent; or a change in obligated DCQ is required at the time of contract renewal or contract amendment.

Upstream Load Factor reflects the percent utilization of upstream assets contracted to serve a Union Gas Delivery Area. The load factor is determined by dividing the forecasted annual utilization of upstream assets for a delivery area by the annual contracted quantity for upstream assets to serve the Delivery Area. Currently the load factors in the Northern and Eastern operations area are 100%.

Policy:

When initiating a contract, the DCQ will be set to reflect the historical and/or forecasted consumption for the contract term. At contract renewal/amendment, the DCQ may be increased or decreased, to reflect the historical and/or forecasted consumption for the contract term. The DCQ for BT contracts is obligated.

Union Gas will determine the obligated DCQ based on the most recent 12 months of actual firm consumption of end use locations underlying the direct purchase contract / 365 days * Heat Value (GJ/m^3)/load factor. If the contract has a term greater than 12 months, the DCQ is calculated by dividing the historical consumption for the term of the contract by the number of days in the contract term. The consumption of general service end-use locations is weather normalized.

Setting the DCQ when initiating a new Direct Purchase contract

Non-telemetered General Service end-use locations served under Rate 01 and Rate 10 with new consumption	▪ End-use locations either transferring from Union Gas's sales service or transferring from an existing direct purchase contract will receive an allocation of Union Gas's Western upstream transportation arrangements.
Telemetered Contract end-use locations served under Rate 20 and Rate 100 with new consumption	▪ End-use locations either transferring from Union Gas's sales service or transferring from an existing direct purchase contract will receive an allocation of Union Gas's Western upstream transportation arrangements.

Increasing an existing Direct Purchase DCQ parameter

Non-telemetered General Service end-use locations served under Rate 01, and Rate 10	▪ Any DCQ increases: due to end-use locations transferring from Union Gas's sales service; or due to end-use locations transferring from an existing direct purchase contract; or due to consumption increases will receive an allocation of Union Gas's Western upstream transportation arrangements,
Telemetered Contract end-use locations served under Rate 20 and Rate 100.	▪ Any DCQ increases: due to end-use locations transferring from Union Gas's sales service; or due to end-use locations transferring from an existing direct purchase contract; or due to consumption increases will receive an allocation of Union Gas's Western upstream transportation arrangements.

Decreasing an existing Direct Purchase DCQ parameter

Non-telemetered General Service end-use locations served under Rate 01, Rate 10	▪ Any DCQ decreases: due to end-use locations transferring to Union Gas's sales service; or due to end-use locations transferring to an existing direct purchase contract; or due to consumption decreases will be managed by decreasing the Customer's Western DCQ.
Telemetered Contract end-use locations served under Rate 20 and Rate 100	▪ Any DCQ decreases: due to end-use locations transferring to Union Gas's sales service; or due to end-use locations transferring to an existing direct purchase contract; or due to consumption decreases will be managed by decreasing the Customer's Western DCQ.

Procedures

1) Union Gas will calculate or recalculate DCQ under the following circumstances:
   a. Upon contract renewal, or
   b. Upon the addition or deletion of end-use locations to/from the contract based on an effective date that is other than the contract renewal date. End-use locations may be added or deleted to the contract pursuant to the Gas Distribution Access Rule Electronic Business Transactions Standard. An amendment to the contract in this event is created at Union Gas's discretion.

2) For direct purchase contracts comprised of telemetered general service and contract rate end-use locations, the DCQ calculation at contract renewal, the calculation will be based on information available approximately 80 days prior to contract renewal. In addition:
   a. Union Gas will issue a Contract Parameters Report summarizing forecast consumption, changes in obligated DCQ, and corresponding changes in upstream transportation allocation consistent with the above policy approximately 70 days prior to the contract's renewal date.
   b. Customer may propose and Union Gas may accept an alternative forecast (with a resulting change in obligated DCQ) provided the contract holder provides justification acceptable to Union Gas for the increase or decrease - a forecast of expected consumption to support the requested obligated DCQ must be provided no later than 54 days before the contract's renewal date. Requests received after this date will be dealt with on a reasonable efforts basis.
   c. Customer will sign back the Contract Parameters Report approximately 54 days prior to the contract's

renewal date.

3) Union Gas will issue a final Contract Parameters Report and contract amendment (reflecting obligated DCQ changes consistent with the above policy) approximately 35 days before the effective date of the amendment for customer signature.

4) Customer will sign and return the contract amendment to Union Gas at least 25 days before the effective date of the amendment.

5) Union Gas will sign the contract amendment and provide a copy to the customer approximately 1 week after receiving the signed amendment from customer.

6) Union Gas will prepare and Union Gas/customer will sign and execute temporary assignment paperwork for upstream pipelines, as necessary, in accordance with their respective schedules.

7) Customer will nominate deliveries to Union Gas reflecting the above contract amendment.