UNION GAS LIMITED

EXHIBIT LIST

PREFILED EVIDENCE OF

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The purpose of this evidence is to address the gas supply-related matters proposed for 2013. The evidence is organized under the following headings:

1/ Gas Supply Plan

2/ Gas Supply Pricing

3/ Upstream Transportation Portfolio

1/ GAS SUPPLY PLAN

The purpose of this evidence is to describe the 2013 Gas Supply Plan. The 2013 (test year), 2012 (bridge year), 2011 (outlook) and the 2010 (historical year) Gas Purchase Expense schedules are found at Exhibit D3, Tab 2, Schedule 1; Exhibit D4, Tab 2 Schedule 1; Exhibit D5, Tab 2, Schedule 1 and Exhibit D6, Tab 2, Schedule 1**,** respectively. The Gas Purchase Expense schedules are consistent with those presented by Union in previous rates proceedings.

1.1/ Gas Supply Plan Planning Process

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 software known as SENDOUT to complete the Gas Supply Plan. Union has used this modeling tool for a number of years and it has been presented in previous rate applications. It was most recently used to support the gas costs approved by the Board in Union's 2007 rates proceeding (EB-2005-0520).

The 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 principles are:

i. Ensure secure and reliable gas supply to Union's service territory;
ii. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
iii. Encourage new sources of supply as well as new infrastructure to Union's service territory;
iv. Meet planned peak-day and seasonal gas delivery requirements; and,
v. Deliver gas to various receipt points on Union's system to maintain system integrity.

Union's five-year Gas Supply Plan, completed during the spring of 2011, includes the following key inputs and assumptions:

i. Union's in-franchise demand forecast based upon customer location (Union North/Union South), supply arrangement (sales service), storage requirement (sales service and direct purchase) and service type (excludes Rate T1, Rate T3, North T-Service and Unbundled service);

ii. A monthly commodity price forecast as described in section 1.6;

iii. Upstream transportation tolls in effect at the time the forecast was prepared;

iv. Heating value of 37.51 $GJ/10^3m^3$ in Union North and 37.75 $GJ/10^3m^3$ in Union South;

v. All upstream transportation contracts held by Union plus existing obligated Ontario deliveries for the bundled direct purchase market;

vi. Sales service and bundled direct purchase storage is cycled completely each year in the plan with storage full on November 1 and empty by March 31;

vii. Sufficient inventory at February 28 to meet the peak day requirements for sales service and bundled direct purchase customers;

viii. No migration between sales service and bundled direct purchase customers for the term of the plan; and,

ix. 9.5 PJ of system integrity space. This storage space is used in a number of ways to maintain the operational integrity of Union’s integrated storage, transmission and distribution systems.

1.2/ Gas Supply Plan Results

The Gas Supply Plan model provides a forecast of Union’s costs required to serve in-franchise sales service and bundled direct purchase customers. These costs are reflected in the Gas Purchase Expense schedules previously referenced.

Union's 2012 to 2016 in-franchise Gas Supply/Demand Balance forecast for sales service and bundled direct purchase customers in 2013 is provided at Exhibit D3, Tab 2, Schedule 3.

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).

1.3/ Upstream Transportation Capacity

Union holds a combination of firm upstream transportation contracts, Dawn sourced supply and storage capacity to meet the full forecast annual demand. Firm transportation arrangements provide direct and secure access to a diverse group of supply basins and hubs in North America. A key objective of the Gas Supply Plan is to optimize the use of upstream contracted pipeline capacity. This is accomplished by managing upstream transportation capacity on an integrated basis and shifting the use of this capacity from one area to serve demand in another area when the opportunity and the need exists.

In Union North, Union utilizes TransCanada Pipelines ("TCPL") and Michigan Consolidated Gas Company/Great Lakes Gas Transmission ("MichCon/GLGT") capacity to meet sales service and bundled direct purchase customer demands. The transportation capacity necessary to meet peak day demands on a firm basis exceeds that required to meet the annual demand requirements. The Gas Supply Plan reflects the effective management of TCPL and MichCon/GLGT capacity by:

i. Using 15.4 PJ of TCPL Storage Transportation Service ("STS") injection and TCPL Dawn Diversions. STS injection is a service that allows Union to move excess volumes from Union North to Parkway and ultimately to Dawn storage in the summer; and,

ii. Using 15.0 PJ of TCPL STS withdrawals primarily in the winter months to serve weather-driven demands. Gas is withdrawn from Dawn storage throughout the winter and is transported back to Union North via STS withdrawals without the need for contracting additional TCPL firm transportation ("FT") capacity to that delivery area.

Using contractual STS pooling rights to group all of Union's STS rights serving the various Union North delivery areas provides Union with the flexibility to serve the individual delivery areas in Union North with gas service in excess of that delivery area's specific STS rights. Unutilized TCPL and MichCon/GLGT FT capacity (held in order to serve peak day firm loads for sales service and bundled customers in Union North that cannot be managed via the above mechanisms) is forecast at 10.4 PJ for the 2013 test year. This results in Unabsorbed Demand Charges ("UDC"). If weather is colder than normal, and if it is economical to do so, Union will use this capacity to meet incremental supply requirements in either Union North or Union South, subject to TCPL's authorization of downstream diversions. This unutilized capacity result has increased from the 2007 Board-approved filing. In EB-2005-0520, the Board approved 4.4 PJ of UDC for unutilized TCPL FT capacity serving the Northern bundled customers. The increase in unutilized capacity is the result of decreases in weather-related throughput in the general service market in Union North as discussed in the evidence of Mr. Paul Gardiner at Exhibit C1, Tab 1, and decreases in Union North contract customer throughput as discussed in the evidence of Ms. Sarah Van Der Paelt and Mr. Paul Gardiner at Exhibit C1, Tab 2.

In Union South, Union utilizes capacity on multiple different upstream pipelines to provide service to meet sales service customer demands. The Gas Supply Plan reflects the effective management of these capacities as there is no unutilized transportation capacity forecast for the 2013 test year as the Plan forecasts a 100% load factor on all Union South upstream transportation. In EB-2005-0520, the Board approved 0.2 PJ for Union South.

The Gas Supply Plan includes 15.3 TJ of Dawn Delivered Service as part of the Union South supply portfolio in 2013, which represents approximately 15% of Union's South sales service purchases. Dawn delivered service supports this diversity by providing Union access to a robust and liquid Dawn market hub. With this diversity, Union is less exposed to price volatility.

Dawn sourced supply is acquired on a month-to-month basis following Union's System Gas - Gas Procurement Policy and Procedures (Appendix A). Purchasing on a month-to-month basis provides Union the flexibility to manage to its seasonal inventory targets without incurring additional UDC.

1.4/ Incremental Supply

If Union is required to purchase incremental supply for unplanned balancing purposes, Union considers its various options in terms of cost effectiveness and operational need. Often these transactions take place at Dawn. Since the November, 2004 implementation of the load balancing checkpoints for bundled direct purchase customers, approved by the Board in the RP-2003-0063 Decision, Union's incremental supply purchases are primarily driven by sales service consumption being greater than forecast (primarily due to colder than normal weather). However, even with direct purchase load balancing checkpoints, Union still retains load balancing obligations related to weather variances relative to the February inventory checkpoints and March weather and consumption variances for both sales service and bundled direct purchase customers.

1.5/ Winter Peaking Service

Union is not forecasting a Winter Peaking Service requirement in Union South for the winters of 2012/2013 and 2013/2014. As discussed in the evidence of Mr. Matt Wood at Exhibit B1, Tab 5, there is no Parkway shortfall forecast on the Dawn-Parkway system for the winters of 2012/2013 and 2013/2014.

1.6/ Pricing

The Gas Supply Plan was prepared in the spring of 2011. The transportation tolls and gas prices utilized in the development of the plan are those used to set the January 1, 2011 Quarterly Rate Adjustment Mechanism ("QRAM") commodity price. These prices are reflected in the Gas Purchase Expense schedules and shown at Exhibit D3, Tab 2, Schedule 1; Exhibit D4, Tab 2, Schedule 1; Exhibit D5, Tab 2, Schedule 1 and Exhibit D6, Tab 2, Schedule 1.

1.7/ Direct Purchase

The Gas Supply Plan includes all bundled direct purchase demand and contracted Daily Contract Quantities (“DCQ”), and assumes that the number of direct purchase customers remains constant as of January 1, 2011. Union is unable to predict customer migration between sales service and bundled direct purchase. Therefore, for the term of the Gas Supply Plan, customers are assumed to remain with the service they had received effective January 1, 2011.

On an actual basis, if customers migrate to direct purchase, Union facilitates this movement by displacing planned commodity purchases and allocating upstream transportation capacity, as per the vertical slice allocation methodology approved in the RP-1999-0017 proceeding and as discussed later in Section 3.1.

1.8/ Weather

The Gas Supply Plan is based upon the 2013 weather normalized demand forecast for in-franchise general service customers, as outlined in the evidence of Mr. Paul Gardiner at Exhibit C1, Tab 5.

1.9/ Storage

Union’s 2011 to 2015 Peak Storage Availability and Utilization forecast is provided at Exhibit C3, Tab 4, Schedule 3. Storage is provided to in-franchise customers to meet the demand requirements of sales service and bundled direct purchase, Rate T1, Rate T3 and Northern T-service customers.

These storage allocation methodologies were approved by the Board as part of the Natural Gas Storage Allocation Policies Decision (EB-2007-0724/0725).

The storage space available to sales service and bundled direct purchase customers in Union South and Union North is determined using the Board-approved Aggregate Excess methodology. This method is defined as the calculation of the difference between total winter demand (November 1 through March 31) and the average annual demand for a 151 day period. This method determines the allocation of storage space based on the following formula:

Aggregate Excess = Total Winter Consumption – [(151/365)*(Total Annual Consumption)]

Union has provided the storage space allocations available to customers electing U2 (unbundled) service in Union South and electing T-service and unbundled service in Union North at Exhibit D3, Tab 2, Schedules 6 and 7, respectively. These allocations are updated annually based on the methodology approved in the EB-2007-0724/0725 Decision.

Accordingly, customers electing T-service and U5/U7/U9 (unbundled) service in Union South have the option of electing the storage space allocation method which best serves their need. The allocation methods available are the Aggregate Excess methodology and the 15 x DCQ methodology.

New large T1 and U7 (unbundled) service customers in Union South with daily firm transportation demand requirements in excess of 1,200,000 m^3/day have the storage space allocation calculated as follows: Peak hourly consumption x 24 hours x 4 days, unless the customer elects firm deliverability less than the maximum entitlement.

If the customer elects less than the maximum deliverability entitlement, the maximum cost based storage space entitlement is 10 x firm storage deliverability contracted (but not to exceed peak hourly consumption x 24 hours x 4 days).

2/ GAS SUPPLY PRICING

The purpose of this evidence is to review Union's gas supply (commodity and upstream transportation) pricing mechanism.

2.1/ QRAM

Union uses the QRAM to set reference prices for commodity and upstream transportation, including the prospective recovery of gas cost related deferral account balances. The existing QRAM process was reviewed and approved in EB-2008-0106.

The major features of the QRAM include:

i. A quarterly change to the commodity reference prices using a 21 day average of the forward 12 months gas prices as indicated on the New York Mercantile Exchange ("NYMEX"), adjusted for the Alberta basis and foreign exchange rate;

ii. The prospective recovery of applicable deferral account balances;

iii. The prospective true-up of historical deferral account variances, between previously projected and actual deferred costs or credits;

iv. TCPL transportation toll changes as approved by the NEB; and,

v. An efficient, consistent and mechanical filing and approval process.

The Board has consistently approved Union's QRAM applications. The QRAM process is working well and Union is not proposing any changes.

3/ UPSTREAM TRANSPORTATION

The purpose of this evidence is to provide information on Union's upstream transportation portfolio commitments.

The North American supply/demand dynamics are changing at a rapid rate. The recent introduction of significant sources of shale supply and the declining production in the Western Canadian Sedimentary Basin ("WCSB") are examples of the changing market dynamics that directly impact the supply choices available to Union. A discussion on the impacts of the changing market dynamics can be found at Exhibit A2, Tab 1, Schedule 1 and Schedule 4. Union's transportation portfolio continues to evolve in response to cost effective supplies available to Ontario. Union's current upstream transportation portfolio is diversified with respect to supply basin access, contract term and transportation service provider. Exhibit D3, Tab 2, Schedule 5 presents Union's Summary of Union's Upstream Transportation Contracts.

3.1/ Southern Allocation of Upstream Transportation Capacity (Vertical Slice)

Union allocates its upstream transportation capacity to Union South customers as they migrate from sales service to direct purchase using the vertical slice methodology approved by the Board in its RP-1999-0017 Decision. The components and relative percentages of the vertical slice are based on Union's projected upstream transportation portfolio as of each November 1 and remain in effect for one year. Union communicates the upcoming vertical slice percentages to customers and the Board in August of each year.

Union's sales service vertical slice upstream transportation portfolio for November 1, 2011 is found at Table 1. This portfolio is being allocated to customers switching from sales service to direct purchase during the period November 1, 2011 to October 31, 2012.

Table 1
Union Gas Limited
Union South Sales Service Vertical Slice Transportation Portfolio
(Effective November 1, 2011)

Transportation	Daily Volume (GJ)	% Portfolio
Alliance/Vector	66,436	27.5%
Vector	85,154	35.2%
Trunkline/Panhandle	21,017	8.7%
Panhandle – Ojibway	26,270	10.9%
TransCanada	42,925	17.8%
Total	241,802	100.0%

3.2/ Union South Transportation Portfolio as at November 1, 2011

The following describes the transportation components in Union's South transportation portfolio and vertical slice:

1) Alliance/Vector

Union holds an existing firm transportation contract on Alliance Pipeline and a corresponding contract on Vector Pipeline. These contracts transport gas from the WCSB and deliver it to Union's system at Dawn. The contracts reflect a volume of 84,405 GJ/d of firm transport with a term of December 1, 2000 through November 30, 2015.

Of the total contracted capacity, 66,436 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology. The Board previously reviewed these transportation contracts in the RP-2001-0029 proceeding. Since that time, Union was required to give Alliance notice by December 1, 2010 to exercise its right to extend the duration of the contract beyond the original termination date of December 1, 2015. Union elected not to extend the term of the contract for economic reasons.

2) Vector

Union holds a second firm transportation contract on Vector Pipeline, transporting gas from Chicago to Union's system at Dawn. The contract reflects a volume of 81,000 Dth/d (85,460 GJ/d) of firm transport for a term of November 1, 2008 through November 30, 2015.

Of the total contracted capacity, 85,154 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

The Board previously reviewed this transportation contract in the EB-2009-0052 proceeding.

3) Trunkline/Panhandle

Union holds an existing firm transportation contract on Trunkline Gas Company from the Gulf of Mexico to Bourbon, Illinois, and a corresponding short-haul contract on Panhandle Eastern Pipe Line from Bourbon to Union's system at Ojibway. The volumes are obligated at Parkway by a firm Ojibway to Parkway service. The contracts reflect a volume of 20,000 Dth/d (21,101 GJ/d) of firm transport for a term of November 1, 2007 through October 31, 2012.

Of the total contracted capacity, 21,017 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

The Board previously reviewed these transportation contracts in the EB-2008-0034 proceeding.

4) Panhandle

Union holds a firm long haul transportation contract with Panhandle Eastern Pipe Line from the Panhandle Field Zone to Union's system at Ojibway. The volumes are obligated at Parkway by a firm Ojibway to Parkway service. This contract reflects a volume of 25,000 Dth/day (26,376 GJ/d) of firm transport for a term of November 1, 2010 through October 31, 2017.

Of the total contracted capacity, 26,270 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology. The Board previously reviewed these transportation contracts in the 2010 Deferral Disposition proceeding, EB-2011-0038.

5) TCPL

In total, Union's South portfolio holds 71,327 GJ/d of TCPL capacity transporting gas from Empress, Alberta to the Union CDA.

Of the total contracted capacity, 42,925 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

3.3/ Union North Transportation Portfolio as at November 1, 2011

The following describes the transportation components in Union's north transportation portfolio.

The vast majority of customers in Union North continue to be served directly from TCPL interconnects. Approximately 95% of Union's long haul TCPL FT contracts and all of Union's TCPL STS contracts have completed their primary term and renew on a 1-year rolling basis. Detailed TCPL contract capacity can be found in Exhibit D3, Tab 2, Schedule 5.

To achieve some supply diversity in Union North, Union contracted for firm transportation from Michigan to the Sault Ste. Marie Delivery Area ("SSMDA") for a volume of up to 6,143 GJ/d beginning November 1, 2011 through October 31, 2014 in order to supply a portion of that delivery area from Michigan. Accordingly, Union holds capacity with MichCon, GLGT and finally on TCPL for service to SSMDA. This path is new for Union beginning in November 1, 2011 and provides some supply diversity to Union North where now 5% of the total Union North system supply is sourced outside of the WCSB.

3.4/ Transportation Committed to Beginning November 1, 2012 – South Portfolio

Niagara – Kirkwall with TCPL

Union holds a firm transportation contract with TCPL for the path Niagara to Kirkwall. The contract quantity is for 21,101 GJ/d (20,000 Dth/d) beginning November 1, 2012 through October 31, 2022 (ten year term).

This contract will become part of Union's upstream transportation portfolio as of November 1, 2012.

unionqas
A Spectra Energy Company

SYSTEM GAS

GAS PROCUREMENT POLICY AND PROCEDURES

April 2010

Gas Procurement Policy and Procedures

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1 INTRODUCTION

Union Gas purchases natural gas for its system operations and regulated system gas supply portfolio. The Gas Procurement Policy and Procedures (the “Policy”) addresses the process of securing natural gas supplies for Union’s system gas customers.

The Policy applies to all system gas purchases.

2 OBJECTIVES

There are five objectives that provide the foundation for the activities that take place under the Policy. The objectives are as follows:

2.1 Provide reasonable value through a diversified portfolio

This objective is intended to achieve a market sensitive price, through the use of diversified tools to provide a reasonable cost of gas for Union Gas ratepayers. This means finding a balance between the use of fixed price contracts, indexed price contracts, and supply basin diversification to achieve this goal.

2.2 Minimize exposure to counterparty credit risk

This objective is in place to recognize the need for prudent credit practices in gas procurement.

2.3 Union ensures fairness to customers and all counterparties in all gas supply transactions

Union ensures that all transactions are carried out with integrity with no preferential treatment shown towards any particular counterparty.

2.4 Corporate Governance and Controls

Corporate Governance is an integral part of the Policy. The gas supply portfolio plans have oversight by senior management. All transactions are approved by senior management and have appropriate internal controls in place. Subject to the Internal Audit department's annual risk assessment, transactions are periodically audited to ensure compliance with the Policy.

3 CONTROLS

There are six independent controls built into the Policy. 1) Corporate Governance through executive review of the gas supply plan; 2) Transactions in the procurement plan approved by the presiding Vice President or Director, Gas Supply, and the Manager, Gas Supply; 3) Absolute segregation of the responsibilities between the front office (transactors) and the back office (transaction administration) functions; 4) Internal audits of the transactions; 5) Exception reporting; and 6) Standard contracts reviewed annually by Finance, Credit, Tax and Legal.

3.1 Corporate Governance

Union Gas executive, at least annually, review and approve the gas supply plan. In accordance with Delegation of Authority, the presiding Vice President, has full authority to implement the plan including the purchase of incremental gas that may be required. The gas supply plan is used to establish the monthly procurement plan.

3.2 Procurement Plan Approval

The Gas Supply department develops the monthly procurement plan. The monthly procurement plan identifies the specific dates for the transactions to be executed.

The presiding Vice President, or Director, Gas Supply and the Manager, Gas Supply or his /her delegate sign the monthly procurement plan. This provides all necessary authorizations for the transactors to execute the transactions in the procurement plan.

3.3 Segregation of Duties

3.3.1 Front Office (Gas Supply)

Gas Supply is responsible for developing and executing the monthly procurement plan. The Manager, Gas Supply or his/her designate is responsible for revising the plan, presenting the plan for appropriate approval, and presenting supporting information for any changes recommended. Once the plan is approved, the Manager, Gas Supply and his/her designate is responsible for:

- Establishing and overseeing the business relationships associated with conducting the plans.
- Ensuring compliance with all credit guidelines provided by Credit.
- Recording all transactions and related terms and informing appropriate persons of all transactions.
- Maintaining price data.
- Reporting of purchases and exceptions from the Policy to Regulatory.
- Providing reports as requested by senior management or the OEB.
- Providing open communication to the OEB and intervenors on policy and procedural updates.
- Initiating a review of the Policy if market conditions warrant or at least every 3 to 5 years.

3.3.2 Back Office (Finance/Credit)

The Finance department performs the administration and accounting of all the transactions. Gas Supply does not have access to post any accounting entries.

The department's responsibilities are:

- Providing first line checking of all transaction invoices received monthly.
- Paying all counterparty invoices. Being responsible for all account reconciliation with the counterparties.
- Providing counterparty credit support as detailed in Section 4, Credit Guidelines.
- Working with Gas Supply to monitor mark to market activity, and performing mark to market calculations for internal and external reporting requirements as required.
- Reviewing standard contracts on an annual basis (Corporate Governance).

Finance must notify the Director, Gas Supply immediately in the event there are any material discrepancies relating to transactions, which could expose the company to legal liability and which remain unresolved after 48 hours. The resolution of any discrepancy with the counterparty is conducted by Finance and/or Gas Supply. The resolution of any disputes are placed in writing and sent to the counterparty with an explanation of the discrepancy and an explanation of how the discrepancy was resolved and the provision that the counterparty consents to the resolution unless the company receives notice otherwise within 48 hours from the receipt.

3.4 Internal Audit of Transactions

Periodically, the Internal Audit department initiates and conducts an audit of transactions. The intent of the audit is to ensure the Policy is being followed. At the discretion of the auditors, a transactor may be directed to be absent from his/her office for at least three consecutive days. This mandatory absence is at the discretion of the Audit department and without prior warning. During that time, the transactor must have no contact with the Audit personnel except as requested by the auditors.

In the event that Audit discovers any discrepancies relating to transactions, settlements, etc. that could expose the company to legal liability, the Director, Gas Supply is notified immediately.

The audit procedures include (but are not limited to):

- Reviewing the transaction activities for compliance with internal guidelines and limits and other company policy and regulatory requirements.
- Reviewing a sample of transactions for accuracy, ensure approved contract is in place.
- Reviewing a sample of transactions to ascertain whether transactions were within the range of same day market prices.
- Tracking a sample transaction through the system, from the initial trade to the closing of the contract period including approval to the general ledger.
- Comparing a sample of confirmations or execution authorizations to the position sheets to ensure that the prices, amounts, etc. are properly transcribed.

- Reviewing the authorizations, transaction summaries and confirmation logs for proper authorization and completeness.
- Reviewing and testing the reconciliation procedures.
- Completing a written report noting any discrepancies or deviations from the Policy and any other irregularities, which could expose the company to legal liability.

3.5 Exception Reporting

The transactors adhere to the Policy as completely as possible in all circumstances. However, Union recognizes that exceptions to the Policy may be required in certain market situations and such exceptions are reported as required.

3.6 Annual Review of Standard Contracts

All standard contracts relating to procurement activity are reviewed on an annual basis by Finance, Credit, Tax and Legal.

4 CREDIT GUIDELINES

The credit guidelines apply to all gas supply transactions. The guidelines reflect the appropriate credit risk for the specific type of gas supply transaction. The intent of the guidelines is to maintain a prudent credit practice balanced with the need to maintain ample alternatives for acquiring gas supplies.

Credit requirements apply to all index transactions. In addition, credit requirements apply to short-term fixed price transactions up to three-months from the transaction date. For example, if the transaction date is in January, the three-month period following the transaction date is February, March and April. Credit requirements would apply to fixed price transactions during this period.

Fixed price transactions extending beyond three months from the transaction date are considered physical hedges and are therefore not permitted under this policy.

4.1 Credit Requirements

Counterparties require an investment grade rating by an acceptable rating agency (Standard & Poors (BBB- and above), Moody's (Baa3 and above), and DBRS(BBB/low and above) and / or an acceptable internal review by the Credit department. Alternatively, a counterparty without a rating, or below investment grade, may be an approved counterparty provided a parent or affiliate that has an investment grade rating guarantees these transactions. Legal and Credit must approve any guarantee offered. In special circumstances a counterparty without an investment grade rating and without a parent or affiliate guarantee may be an approved counterparty at the discretion of the Credit department in accordance with Union Gas Credit guidelines.

Any approved counterparty receives a credit limit assigned by the Credit department. Upon request from the Gas Supply department, the Credit department considers raising the credit limit for specific counterparties in accordance with Union Gas Credit guidelines and within the Credit department's Delegation of Authority.

If at any time counterparty's credit exposure is greater than the authorized credit limit, Credit informs the Director, Gas Supply and the he/she recommends a course of action to bring the counterparty within authorized credit limits by either raising the limit, if appropriate, or restricting transactions with the counterparty until they are within limits.

If Credit has reason to be concerned about the financial stability of any counterparty, Credit notifies the Director, Gas Supply, and Legal. Credit, Legal and the Director, Gas Supply develops a course of action to limit Union's financial liability consistent with the provisions of the gas purchase agreement in place with the counterparty.

5 SUPPORT DEPARTMENTS

5.1 Tax Department

The Tax department provides the Gas Supply and the Finance departments with any updates or implications of any proposed or pending tax legislation that affects the program or transactions. The Gas Supply and Finance departments seek the advice of the Tax department as required. The Tax department reviews the standard contracts on an annual basis (Corporate Governance).

5.2 Legal

Legal is responsible for reviewing contractual terms and establishing Union's standard gas purchase agreement (GPA) or a NAESB for counterparties. Once a standard format of each of the documents has been approved by legal, any future sign off by legal is not required. If there are any subsequent changes to the formatting or the wording, or potential law changes then a proper review and sign off are required by legal for any new documentation. Legal reviews the standard contracts on an annual basis (Corporate Governance).

6 AFFILIATE TRANSACTIONS

All counterparties are treated equally and no preferential treatment is given to affiliated companies. Any transaction conducted with an affiliated company complies with the Ontario Energy Board's Affiliate Relationships Code for Gas Utilities.

7 APPROVED TRANSACTION INSTRUMENTS

7.1 Transaction Instruments

Union Gas is authorized to use the following transaction pricing instruments either through the RFP process (written and verbal), electronic gas trading platforms or a brokerage house.

- Fixed price contracts specify purchase of natural gas at a fixed price for a specific term.
- Index price contracts specify purchase of natural gas at a price to be determined in the future for a specific term.
- Price trigger contracts are a hybrid of fixed and index contracts. Initially, the contract is index and Union has the right to fix the price over the contract term.

8 GAS PROCUREMENT PROCEDURE

The following provides an overview of the procedures and related internal controls that must be followed when conducting a transaction.

8.1 Request For Proposal's (RFP's)

8.1.1 Written RFP's

Written RFP's are sent to prospective suppliers by email based on the appropriate counterparty list. Responses to written RFP's are received by email or facsimile.

Emails are sent and received by the ”UniongasRFP” mailbox. It is the responsibility of the supplier to ensure that proposals are received by the closing time. Suppliers offering late proposals are notified that their proposal was rejected due to being late. Reasonable allowances are made for communication problems.

In the case where the initial price has changed due to market volatility, Union calls the next best offer to ensure the price change requested is legitimate and reasonable and that the original successful supplier still has the best price. Verbal quotes to finalize the transaction are electronically recorded. Recordings are kept for a period of one year following the transaction.

8.1.2 Verbal RFP’s

Verbal RFP’s are used by exception, primarily for purchases outside the monthly procurement plan. In addition, given the volatile nature of natural gas pricing, it may from time to time, be in the best interests of Union’s customers to use a verbal (by phone) tendering procedure. This procedure is used to minimize price disadvantage (eg. in a market of rising prices) or take advantage of price opportunities that materialize from time to time. Supplier short lists (by delivery point) are used in this process to facilitate its timely turnaround with the market. This procedure is intended to complement, not replace the written RFP process by obtaining market responsive pricing without compromising the principle of fairness to both customers and suppliers.

Verbal RFP’s are issued only to suppliers who have returned an executed copy of Union’s Gas Purchase Agreement or NAESB and those who consistently respond to RFP’s for gas sales at the delivery point and consistently make competitive price offers. Verbal quotes are electronically recorded. Recordings are kept for a period of one year following the transaction.

9 GLOSSARY

Back Office - The management and staff that have the primary responsibility for accounting, payables/receivables management, reporting and credit matters.

Basis - The differential that exists at any time between the futures price for a given commodity and the comparable price at a different physical location.

Canadian Gas -Gas delivered in specific regions in Canada.

Counterparty – The person or institution standing on the opposite side of a transaction.

Credit Risk – The risk of default by either counterparty in a transaction.

Front Office - The management and staff that have the primary responsibility for counterparty contact and transacting.

Futures Exchange - A location where trading in commodities is conducted in accordance with other specific rules, procedures and guarantees (i.e. New York Mercantile Exchange (NYMEX)).

Gas Purchase Agreement - Any of Union Gas Limited's contracts for gas purchases

NAESB - North American Energy Standard Board standard gas purchase agreement.

New York Mercantile Exchange (NYMEX) - The world's largest commodity futures exchange and preeminent trading forum for energy in North America, the NYMEX is a regulated financial institution that provides a centralized marketplace to increase market efficiency through the competition among many buyers and sellers.

Request for Proposal (RFP) - A request by a prospective party to a contract, asking other potential parties to a contract, for proposals on the key principles and terms related to an expected transaction. Either the seller or buyer may issue a request for proposal, although normally the buyer issues the request. The party requesting normally outlines the key proposed conditions of purchase and sale, but may permit alternative forms and conditions.

US Gas - Gas delivered in specific regions in the United States.

PREFILED EVIDENCE OF

BETH CUMMINGS, MANAGER OF O&M AND CAPITAL REPORTING

The purpose of this evidence is to provide an overview of Union's Operating and Maintenance ("O&M") expenses for the 2013 test year. Summaries of projected costs by cost type are provided at Exhibit D1, Summary Schedule 2 and variance explanations from the prior year are provided at Exhibit D3 through Exhibit D5, Tab 3, Schedule 2, for 2013, 2012 and 2011, respectively. Summaries of 2010 actual costs by cost type and variance explanations to the 2007 Board-approved costs are provided at Exhibit D6, Tab 3, Schedule 2.

The O&M forecast presented in this evidence is a consolidation of the budgets prepared for various departments within Union. The individual department budgets were developed using a common set of assumptions as set out in the budget instructions as well as department specific workload, service and operating requirements. The methodology used to allocate O&M between the regulated and unregulated business is provided at Exhibit A2, Tab 2. The forecast is consistent with Union's goals of providing cost effective service to customers while maintaining safety, system integrity and reliability, addressing customer service needs, government directives and requirements, and environmental concerns. A summary of the operating budget process is provided at Exhibit A2, Tab 3, Schedule 1.

1/ 2013 TEST YEAR COMPARISON TO 2007 BOARD-APPROVED

Union's utility O&M forecast for the 2013 test year is forecast to be $393.2 million. The forecast reflects increases due to human resource costs, inflation, customer growth, compliance and safety programs and is offset partially through productivity and a reduction of utility costs as resources were re-directed to affiliate work, unregulated work and apportioned to capital work.

In addition, utility costs have increased by $14.8 million from the 2007 Board-approved budget for Demand Side Management ("DSM") compared to the DSM budget proposed in EB-2011-0327. Table 1 provides a comparison of 2013 O&M forecast spending to 2007 Board-approved levels.

Table 1
Summary of Utility Increase
Forecast 2013 vs. Board-approved 2007

Line No	Particulars ($ Millions)	
1	Forecast 2013 Utility O&M	393.2
2	Less Cross-Charge	(2.3)
3	Forecast 2013 Utility O&M Less Cross-Charge	390.9
4	Less Board-approved 2007 Utility O&M (EB-2005-0520)	(325.6)
5	Less Incremental DSM (EB-2011-0327)	(14.8)
6	Increase to Utility Costs excluding DSM	50.5

The increase to utility costs excluding DSM is $50.5 million or 15.5% over the 2007 Board-approved costs. This equates to an average increase from 2007 Board-approved to 2013 of approximately 2.6% per annum.

The primary drivers for the increase in O&M expense are outlined in Table 2 below.

Table 2
Summary of O&M Expense Changes by Major Driver
Forecast 2013 vs. Board-approved 2007

Line No	Particulars ($ Millions)		
	Human Resource related cost increases		
1	Compensation	32.9	
2	Benefits	25.5	
3	Workforce Development and Enhancement Initiative	2.6	61.0
4	Inflation		17.5
5	Customer Growth		12.2
6	Integrity Management		6.5
7	Energy Technology & Innovation Canada		5.0
8	Line Locates		3.9
9	Productivity		(22.5)
10	Capitalization		(14.1)
11	Affiliate Services		(8.0)
12	Non-Utility Allocation		(6.9)
13	Bad Debt Expense		(5.0)
14	Other		0.9
15	Total		50.5

Human Resources Related Costs

Human Resources costs have increased by approximately $61.0 million between 2007 Board-approved costs and the 2013 test year forecast. This increase is primarily driven by salary and wage increases between 2008 and 2011 and projected salary increases for 2012 and 2013 of 3.0% and 3.5% respectively. In addition to salary and wage increases, costs also increased for pension and benefits and the Workforce Development and Enhancement Initiative. Pension, benefits and compensation costs are discussed in detail in the evidence of Mr. Bohdan Bodnar, Ms. Pat Elliott and Mr. Chuck Conlon at Exhibit D1, Tab 3.

The salary increases contained in the 2012 and 2013 forecast were 3.0% and 3.5% as reflected in the updated Economic Assumptions in Exhibit A2, Tab 3, Schedule 1, Appendix A. The budget instructions at Exhibit A2, Tab 3, Schedule 1, Appendices B and C were written prior to the updated assumptions and reflect an earlier assumption of 3.5% and 4.0% for each year.

Inflation

Union has assumed that inflation will increase costs other than salary, pension/benefits and DSM by $17.5 million between the 2007 Board-approved and the 2013 test year. This is calculated using the actual Canada CPI inflation rate for the years 2007 through 2010 and using a projected average rate of inflation of 2.2%, 2.1% and 2.1% per annum for the years 2011 through 2013, respectively.

Customer Growth

Customer growth-related costs are forecast to increase by $12.2 million from 2007 to the 2013 test year. The total number of general service customers forecast for 2013 is approximately 110,250 higher than the 2007 year end customer count. This reflects an actual increase of 54,469 customers from year end 2007 to year end 2010 and a projected increase of 55,781 customers for the period 2011 through 2013. Total customers by service type and rate class is found at Exhibit C1, Summary Schedule 2. The annual variable O&M cost Union incurs when customers are attached to Union's system is estimated to be approximately $110 per customer, based on the 2007 cost study. The costs associated with adding customers includes costs of bill inserts, postage, meter reading and maintaining additional distribution services and meter sets.

Integrity Management

Union's costs in the 2013 test year are forecast to increase $6.5 million over the 2007 actual costs as a result of changes to the Integrity Management Program ("IMP"). This program is described in more detail in the evidence of Mr. Doug Alexander at Exhibit B1, Tab 6.

Line Locates

Using internal and external resources to provide the physical location of Union's pipelines to excavators and homeowners is critical to mitigate third party damage and ensure public safety. Union works diligently to promote "call before you dig" programs which help increase public awareness and ultimately increase the number of line locate requests. This increase in requests has resulted in the line locate costs forecast for 2013 to be $3.9 million higher than the actual 2007 costs.

Energy Technology & Innovation Canada

Union is a member of Energy Technology & Innovation Canada ("ETIC"). ETIC's vision is "to ensure that natural gas and gas-enabled technologies remain a significant part of Canada's low carbon energy future, through strategic investment in technology commercialization and innovation". The 2013 forecast cost for ETIC is $5.0 million. Details of this program are described in the evidence of Mr. Bryan Goulden at Exhibit D1, Tab 10.

Productivity

For the years 2008 through 2011, Union completed several productivity initiatives. Actual productivity experienced during this period is forecast to be $15.9 million. For the years 2012 and 2013, Union has assumed annual productivity targets of 1% which accounts for an additional $6.6 million. This results in a productivity gain of $22.5 million for 2013 compared to 2007. Details on productivity projects are described in the evidence of Mr. Dave Richards at Exhibit A2, Tab 5.

Capitalization

Capitalized overheads, which includes capitalization and loadings has increased $14.1 million between 2007 Board-approved costs and the 2013 test year forecast. This increase is the result of increased capital expenditures over the 2007 to 2013 period as well as general inflationary increases to the items that are capitalized (e.g., salaries are higher, pension/benefits are higher, etc).

Union has continued to rely on the capitalization rates as determined by an independent capitalization study by KPMG that was prepared for Union’s 2007 rate case (EB-2005-0520).

The capitalized overhead costs forecast in 2013 are 15.2% of total costs. This is consistent with the 2007 Board-approved level of 15.0%.

Net Affiliate Services

Changes to net Affiliate revenues and expenses in the 2013 test year relative to the 2007 Board-approved are expected to decrease by approximately $8.0 million. The changes to Affiliate revenues and expenses since 2007 are described in evidence of Mr. Dave Hockin at Exhibit D1, Tab 7.

Non-Utility Allocation

Union's costs allocated to the non-utility business in 2013 are forecast to increase $6.9 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.

Bad Debt Expense

Union's forecast of bad debt expense for each of 2012 and 2013 is $6.6 million. This is a decrease of $5.0 million from the amount included in rates approved by the Board in EB-2005-0520. The reduction is mainly due to the decrease in cost of gas and improvements in the collection process, resulting in a higher rate of payment from accounts in arrears.

Table 3 shows the calculation of the forecast for 2012 and 2013 bad debt O&M expense. The forecast for bad debt expense in the general service market is based on an average of the actual experience for the previous five years, 2006 to 2010 of 0.31%. The risk of uncollectible accounts in the contract market is dependent on economic circumstances. Accounts in the contract market are managed on an individual customer basis. Actual write offs in the contract market over the past five years range from $0.0 million to $0.6 million. The 2012 and 2013 forecast includes an estimate of $0.3 million for write offs in the contract market.

Table 3
Bad Debt Expense

Line No.	Particulars ($ millions)	2007 Board-Approved (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)
1	Revenue - including ABC billings	2,666.9	2,112.1	1,914.2	1,875.
2	Write off ratio - %	0.41	0.19	0.31	0.31
3	General service provision	10.85	4.1	5.9	5.9
4	Contract service provision	0.75	0.1	0.3	0.3
5	Bad debt provision	11.6	4.2	6.2	6.2
6	Collection costs	0.5	0.2	0.2	0.2
7	GST/HST non recovery	0.2	0.1	0.2	0.2
8	Bad debt related expense	12.3	4.5	6.6	6.6

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 10^3m^3. An increase of 10% in WACOG will increase Union's bad debt expense approximately $0.4 million.

Full Time Equivalents ("FTE")

Union's 2013 test year forecast includes compensation and employee related expenses for approximately 2,248 FTE. This is an increase over the year-end 2010 actual of 37 FTE. This number reflects all employees working on utility operations, capital projects, unregulated activities and DSM.

The most significant contributor to this increase 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.

The total number of FTE's is derived by converting part-time roles into full-time equivalents using hours worked and adding the number of full time roles.

2/ YEAR OVER YEAR CONTINUITY FOR O&M BUDGET VARIANCE

A summary of the major variances by cost type have been shown for 2010 actual, 2011 actual, 2012 bridge year forecast and 2013 test year forecast relative to the 2007 Board-approved budget in Table 4.

Table 4
Year Over Year Continuity for O&M

Line No.	Particulars ($ Millions)	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	Total
1	Board approved (RP-2005-0520)	325.6				325.6
2	Prior period		349.4	369.5	381.5	
3	Salaries/Wages	23.4	8.6	(3.9)	5.8	33.9
4	Benefits	15.2	10.3	1.0	(1.1)	25.4
5	Employee Training	(1.0)	1.7	0.6	0.2	1.5
6	Contract Services	7.3	6.3	0.1	2.7	16.4
7	Consulting	1.1	0.2	3.4	2.1	6.8
8	General	0.6	1.1	(0.7)	0.6	1.6
9	Company Used Gas	(2.5)	(0.1)	0.1	0.0	(2.5)
10	Utility Costs	0.4	0.4	0.5	0.1	1.4
11	Communications	(1.2)	(0.4)	(0.2)	0.1	(1.7)
12	Demand Side Management Programs	4.6	1.5	5.7	0.6	12.4
13	Insurance	1.5	(0.4)	0.5	0.5	2.1
14	Computers	0.7	0.4	0.9	0.3	2.3
15	Regulatory Hearing & OEB Cost Assessment	(2.9)	0.2	1.9	(0.9)	(1.7)
16	Affiliate Services	(6.9)	(2.0)	0.6	0.4	(7.9)
17	Bad Debt	(6.5)	(0.6)	2.1	0.0	(5.0)
18	Other	(1.9)	1.3	2.0	1.7	3.1
19	Capitalization	(1.4)	(7.1)	(2.4)	(3.2)	(14.1)
20	Non-Utility	(5.0)	(1.3)	(0.2)	(0.4)	(6.9)
21	Excess Utility Cross Charge	(1.7)	-	-	-	(1.7)
22		23.8	20.1	12.0	9.5	65.4
23	Current period	349.4	369.5	381.5	391.0	391.0

2013 Test Year Forecast vs. 2012 Bridge Year Forecast

Union's 2013 Net Utility O&M budget less Cross-Charge is $390.9 million. This is an increase of $9.5 million over the 2012 forecast. The details of the variance between the 2013 O&M test year budget and the 2012 bridge forecast are provided at Exhibit D3, Tab 3, Schedule 2 and major variances are summarized below.

Salary and wages are forecast to increase $5.8 million largely due to a 3.5% increase applied to base salary.

Contract services are forecast to increase $2.7 million due to increased costs for the integrity management program, line locate services and Enlogix CIS ("Banner") transactional fees.

Consulting services are forecast to increase $2.1 million largely due to the ETIC program and inflation.

These increases are offset by an increase in capitalization of $3.2 million due to increases to the items above that are capitalized (salaries, pension/benefits).

2012 Bridge Year Forecast vs. 2011 Actual

Union's O&M budget for 2012 is $381.5 million. This is an increase of $12.0 million over 2011 actual. The details of the variance between the 2012 forecast and 2011 actual are provided at Exhibit D4, Tab 3, Schedule 2 and major variances are summarized below.

Salaries and wages are forecast to decrease $3.9 million due to lower planned incentive plan costs for 2012 compared to 2011 actual costs.

DSM programs are forecast to increase $5.7 million as per Union's EB-2011-0327 application.

Consulting services are forecast to increase $3.4 million largely due to the ETIC program.

These additional costs are partially offset by forecast increases of $2.4 million in capitalization.

2011 Actual vs. 2010 Actual

Union's actual O&M expense for 2011 was $369.5 million. This is an increase of $20.1 million over 2010 actual. The details of the variance between the 2011 actual and the 2010 actual are provided at Exhibit D5, Tab 3, Schedule 2 and major variances are summarized below.

Pension and benefits costs increased $10.3 million largely due to continuing high levels of medical price inflation and historic low-levels of long-term bond yields and pour capital market returns.

Salary and wage costs increased $8.6 million largely due to merit increases and incremental incentive payout.

Contract services increased by $6.3 million due to increased costs for integrity work, line locates and inflation.

These additional costs are offset by increases in capitalization of $7.1 million due to a larger capital portfolio in 2011 compared to 2010 and by the higher costs in salary/wages and pension and benefits that are subject to capitalization.

2010 Actual vs. 2007 Board-approved

Union's actual O&M for 2010 was $349.4 million. This represented an increase of $23.8 million or 7.3% over the 2007 Board-approved costs, which is approximately a 2.4% increase per annum. The details of the variances between the 2010 actual and the 2007 Board-approved costs are provided at Exhibit D6, Tab 3, Schedule 2 and major variances are summarized below.

Salary and wage costs increased $23.4 million for the 3 year period. This increase reflects annual merit increases and increases to the incentive payout.

Pension and benefits costs increased $15.2 million. Pension, benefits and compensation costs are discussed in detail in the evidence of Mr. Bohdan Bodnar, Ms. Pat Elliott and Mr. Chuck Conlon at Exhibit D1, Tab 3.

Contract Services increased $7.3 million due to increased volumes of line locates and increased maintenance and integrity work. It also increased as a result of a major repair that was offset with recovery dollars.

DSM programs increased $4.6 million.

These costs were partially offset by reductions in affiliate services, lower bad debt expense, lower Board costs and lower Company use gas costs. In addition, an incremental proportion of total costs were directed to non-utility work and changes to the excess utility cross charge.

PREFILED EVIDENCE OF

BOHDAN BODNAR, VICE-PRESIDENT, HUMAN RESOURCES CANADA

CHUCK CONLON, DIRECTOR, EMPLOYEE AND LABOUR RELATIONS EAST

PAT ELLIOTT, CONTROLLER

The following evidence identifies and explains proposed changes to the assumptions used to calculate Union's defined benefit ("DB") pension and post-retirement benefits cost forecast for 2012 and 2013.

The need for this update is driven by two key issues:

- 2011 actual plan performance
- Updates to assumptions:
  - Discount rate
  - Rate of Return on Assets
  - Mortality Rate

As stated in the November 2011 filing, since establishing the estimates used in the original forecast, economic conditions have changed with the result being the need to increase the DB pension and post-retirement benefits cost relative to the original forecast.

In its original filing, Union's DB pension cost forecast for 2012 and 2013 was based on the same key assumptions that were finalized at the 2010 year end and used in the preparation of the 2011 DB pension cost. These assumptions included a discount rate of 5.25%, a rate of return on assets of

7.00% and a mortality assumption of 90% of the UP94 mortality table projected generationally using Scale AA. However, on page 11 of its original evidence Union noted that an evidence update would be required. Specifically, it noted that the DB pension cost estimate to be included in 2013 base rates be based on assumptions finalized at the 2011 year end.

As shown on Table 4 Updated (Comparison of Employee Future Benefit Costs), the most significant change resulting from the pension adjustment is the comparison between 2012 and 2013 original and updated DB pension and post-retirement benefit cost totals. Specifically, the 2012 original DB pension cost of $26.8 million was updated to $36.2 million while the 2013 original DB pension cost of $15.7 million was updated to $34.2 million. When comparing the total employee future benefit costs for 2011 to 2013, the totals are relatively flat. Post-retirement benefit costs have also been updated in 2012 and 2013 for the updates to assumptions described below.

2011 Actual Plan Performance

The original 2012 and 2013 DB pension cost forecast assumed the plan assets at the beginning of 2011 would realize a return of 7.0% during the year. The actual return on assets for 2011 was 0%. The actual DB pension cost in subsequent years is increased due to the actuarial loss incurred in 2011 as a result of not realizing the expected return.

Updates to Assumptions

The discount rate is calculated using a hypothetical AA Corporate yield curve for long Canadian bonds. Between the 2010 and 2011 year end, this yield curve has decreased from 5.25% for DB pension to 4.30% and from 5.31% for post-retirement benefits to 4.33%. This decrease in the yield curve has increased the 2012 and 2013 pension costs from the original forecast. The 2013 pension costs in this update were projected using the 2011 year end discount rate. The actual discount rate will be known following the 2012 year end and will be different than the assumption used in this updated forecast.

Union has updated the assumptions related to expected return on plan assets from 7.00% in 2011 to 6.75% in 2012 and 6.50% in 2013. This reduction is to reflect the low returns being experienced in the marketplace in addition to broad industry benchmarking information.

Union has also updated the mortality assumption for 2013 to more accurately reflect the experience in the plans and to align the accounting expense with the funding assumptions. The assumption was updated from 90% to 80% of the UP94 mortality table projected generationally using Scale AA.

PREFILED EVIDENCE OF
BOHDAN BODNAR, VICE-PRESIDENT, HUMAN RESOURCES CANADA
CHUCK CONLON, DIRECTOR, EMPLOYEE AND LABOUR RELATIONS EAST
PAT ELLIOTT, CONTROLLER

The purpose of this evidence is to provide an explanation for the Human Resource ("HR") costs from 2007 to 2013. This evidence is organized under the following headings:

1/ Total Cash Compensation Costs
2/ Pension and Benefits
3/ Employee Future Benefit Costs
4/ Payroll/Human Resource Management System
5/ Workforce Demographics

1/ TOTAL CASH COMPENSATION COSTS

The goal of Union's compensation strategy is to attract, motivate and retain high calibre employees to ensure the Company's success. To help meet this goal, Union offers employees a total cash compensation package that consists of a fixed component (base salary – salaries and wages) and a variable, at risk pay component (Short-Term Incentive Plan – "STIP"). A small number of key leadership employees also have a long-term variable pay component ("LTIP") as part of their total compensation. Each of these compensation components is critical to the success of Union's total compensation package in the competition for talent and the retention of a high performing workforce. For more detail on Union's total cash compensation package, please refer to the Towers

Watson "Union Gas 2013 Rate Application – Total Cash Compensation" letter provided at Appendix A.

Compensation levels are based on market conditions to ensure Union's ability to compete for required talent and to retain valued employees. Union's compensation philosophy continues to target total cash and total direct compensation levels to the 50th percentile in the marketplace at target variable pay levels. To validate the competitiveness of its compensation levels, Union compares its compensation levels to a cross-section of national companies of similar revenue size; including energy utilities as well as organizations with operations in Ontario. This compensation philosophy and approach to competitive market analysis has been supported by Union since 2001. In fact, as stated in Appendix A, Towers Watson concluded that "Union Gas' salary increases and target incentive levels are appropriately aligned with competitive market practice."

Base Pay

Base salaries and wages form the foundation of Union's compensation program. Base salary budgets are set with consideration given to Towers Watson's forecasts of salary increases, negotiated wage settlements and consumer price index projections. Annual base salary increases for non-union employees are administered against established guidelines including individual performance, demonstrated growth and development, and are inclusive of increases to salary ranges. Unionized employee wage increases are determined through collective agreements negotiated through collective bargaining.

Union's 2013 base salary budget is forecast to be $174.8 million, an increase of $24.9 million from the 2007 actual total. This increase accounts for salary increases, salary progressions as employees develop their skills and promotions, changes in staffing and overtime, as well as the cost impacts associated with an aging workforce as discussed later in this evidence. Table 1 provides a comparison of Union's base salary and variable pay actual costs for years 2007, 2010 and 2011 and totals for 2012 to 2013 forecast.

Table 1
Comparison of Salary & Wage Costs

Line No.	($000's)	2007 Actual (a)	2010 Actual (b)	2011 Actual (c)	2012 Forecast (d)	2013 Forecast (e)
1	Base Pay	149,843	159,441	166,627	169,622	174,756
2	Variable Pay	14,528	23,808	25,210	18,328	19,030
3	Total	164,371	183,249	191,837	187,950	193,786

Total salary and wage costs for all years in Table 1 are shown at Exhibit D1, Summary Schedule 2.

Variable Pay

Union's annual variable pay program, STIP, provides an opportunity for awards based on the successful achievement against corporate, business unit and individual/team objectives. All employees at all organizational levels, both union and non-union, participate in this variable pay plan. The variable pay program design for unionized employees is determined through the collective bargaining process. A document that describes Union's 2011 STIP plan is attached as Appendix B. Union believes one of the most effective ways to help improve efficiency or productivity of the Company is to link its employees to a combination of financial and operational results through a "balanced scorecard" method of performance management. The balanced scorecards are a collection of metrics that are aligned with the business strategy of each operating unit. They ensure Union is meeting the expectations of its external stakeholders (i.e. ratepayers, customers, investors, regulators). They also ensure Union has safe, efficient, effective processes and a skilled, knowledgeable workforce to carry out those strategies. Ratepayers benefit from specific employee focus related to personal safety, operational safety, integrity, reliability, compliance and productivity. Balanced scorecard metrics are reviewed annually based on history with a level of stretch built in to ensure continuous improvement including productivity improvements. The balanced scorecard method of performance management measures success from four broad perspectives:

1. Employee – to ensure employees are equipped with the tools and skills needed to carry out Union's processes (e.g. safe work environment);
2. Process Excellence – to ensure efficient processes are in place to deliver on customers' expectations;
3. Customer – to ensure customers' expectations are being fulfilled and compliance requirements are met; and,
4. Financial – to ensure shareholders' expectations are met.

The balanced scorecard method provides alignment for employees at all organizational levels. An overview which describes the purpose, structure and benefits of the Operations Balanced Scorecard is filed at Appendix C.

Annual variable pay plans such as STIP are common in the marketplace where Union competes for talent. Without an annual, variable pay plan, Union would need to increase base salary levels to retain existing employees and to compete for new talent since its competitors' total cash compensation packages include variable pay. A shift away from variable pay in favour of increased base salaries would increase Union's fixed costs and reduce Union's ability to align employee performance with business priorities and reward employees for successful performance results. Therefore, including a variable pay component within the total compensation package at Union is a reasonable and prudent methodology for compensating employees.

As mentioned previously, approximately 30 executive and leadership employees at Union participate in an additional variable pay plan, the Long-Term Incentive Program ("LTIP"). This plan is a stock-based plan consisting of two types of awards: performance share units and phantom stock units. Effective for 2011, performance share units account for 60% of the participants' LTIP opportunity (increased from 50%). These units are subject to vesting, after a specified performance goal relative to a peer group of energy companies has been achieved during continuous employment. Phantom stock units account for the remaining 40% of the participants' LTIP opportunity. Phantom stock units vest on the third anniversary of the grant date during continuous employment.

Participation in LTIP is determined by the Compensation Committee of the Board of Directors of Spectra Energy and is restricted to the top, key decision makers in the Company based on the following criteria: the position has a key corporate or business unit role; the employee manages major projects with strategic impact; the function contributes significantly to the bottom line; and, the marketplace supports long-term incentive compensation for the position.

The intent of this plan is to provide a balance between near-term performance and long-term success. This plan enables senior leadership participants to be rewarded for creating long-term value to the benefit of shareholders and ratepayers. It also aids in retention of key executive and leadership talent.

Table 2 shows the actual average employee salary and incentive total for the years 2010 and 2011 and forecast totals for 2012 and 2013. A more detailed description of the variances in salaries and wages year-over-year is provided at Exhibit D3, Tab 3, Schedule 2 – 2013 vs. 2012; Exhibit D4, Tab 3, Schedule 2 – 2012 vs. 2011; and, Exhibit D5, Tab 3, Schedule 2 – 2011 vs. 2010. Table 2 is calculated using salary data that includes both O&M and capital salaries and the related full-time equivalents ("FTE") for the years summarized.

Table 2
Average Employee Total Cash Compensation Comparison (2010-2013)

Line No.	Particulars ($)	2010 Actual (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)
1	Average Salary	77,727	80,983	78,671	81,351
2	Average Variable	10,769	11,360	7,903	8,213
3	Total	88,496	92,343	86,574	89,564
4	Year over year		4.3%	(6.2%)	3.5%

2/ PENSION AND BENEFITS

Union provides a comprehensive pension and benefits program that is essential to attract and retain qualified employees. Union provides a common platform of pension and benefits to all employees, both union and non-union.

In addition to statutory programs and a short-term disability plan, the program provided by Union consists of:

i) Benefit Choices – A flexible benefits program for all active employees, with benefit options selected by each employee;

ii) Employee Savings Plan – A voluntary employee savings plan with matching employer contributions dependent on years of service;

iii) Pension Choices – A choice of a Defined Benefit ("DB") or Defined Contribution ("DC") pension plan at the election of each employee; and,

iv) Post-Retirement Benefits – A retiree benefits program providing basic life insurance and medical benefits not covered by the Ontario Health Insurance Program.

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. The objective is to provide programs that target the median in terms of employer provided value as compared to programs offered by this comparator group of companies, and is designed to manage and contain costs consistent with the market and economic environment. This philosophy and approach to competitive market analysis has been supported by Union since at least 2001.

Union has retained Towers Watson to provide independent, expert commentary on Union's employee benefit arrangements. Please refer to Appendix D for Towers Watson's "Benefit Programs" letter.

Benefit Costs

Benefit costs for 2013 are forecast to be approximately $33.7 million an increase of $8.5 million from the amount included in Union's Board-approved 2007 rates. Table 3 provides a comparison of actual and forecast benefit costs to the costs approved by the Board in EB-2005-0520.

Table 3
Comparison of Benefit Costs

Line No.	($ millions)	Board Approved (a)	2007 Actual (b)	2011 Actual (c)	2012 Forecast (d)	2013 Forecast (e)
1	Employee Benefits	$25.2	$26.7	$32.9	$32.2	$33.7

The Benefit Choices program was designed to manage overall benefit costs and to share costs with employees. Changes are made each year to the price tags for the benefit options to maintain the target level of cost sharing of benefit costs between Union and its employees.

In common with other employers, Union has experienced benefit cost increases significantly in excess of consumer price inflation. However, Union has pro-actively managed its benefit costs and Union's cost increases have been materially below industry norms.

To continue to manage and control employee benefit costs and benefit delivery costs;

i) In 2009, Union introduced a prescription drug card that permits more effective cost management and analysis of drug costs, which typically account for 60% to 70% of overall employee medical costs; and,

ii) In 2010, Union undertook a comprehensive marketing of its group insurance and administration arrangements for employee benefits. As a result of this exercise, Union secured premium reductions and guarantees as well as improved administrative terms and conditions.

The Employee Savings Plan ("ESP") has not changed since 2007. Participation in the ESP is voluntary. The Company's matching contributions are based on the employee's years of service up to a maximum of 5% of their annual base salary.

3/ EMPLOYEE FUTURE BENEFIT COSTS

Union sponsors five legacy defined benefit registered pension plans and one registered pension plan ("Pension Choices") with both a defined benefit provision ("DB") and defined contribution provision ("DC"). The five legacy DB pension plans are all closed to new entrants; newly hired employees are admitted to Pension Choices. Eligible employees participate in only one of the DB or DC pension plans, based on each employee's election at the time of plan enrollment.

Pension and post-retirement benefit costs for 2013 are forecast to be approximately $47.4 million; an increase of $17.0 million from the amount included in Union's Board-approved 2007 rates. Table 4 provides a comparison of the forecast pension and benefit costs for 2013 to the costs approved by the Board in EB-2005-0520.

Table 4
Comparison of Employee Future Benefit Costs

Line No.	($ millions)	Board-Approved (a)	2007 Actual (b)	2011 Actual (c)	2012 Forecast (d)	2013 Forecast (e)
1	Defined Benefit Pension	$19.3	$21.5	$35.4	$36.2	$34.2
2	Post-Retirement Benefits	8.3	5.4	7.9	8.5	7.6
3	Defined Contribution Pension	2.8	2.8	5.0	5.3	5.6
4	Total	$30.4	$29.7	$48.3	$50.0	$47.4

Defined Benefit Pension

The DB pension costs for 2013 are forecast to be approximately $34.2 million, an increase of $14.9 million from the amount included in Union's approved 2007 rates. The increase in DB costs is the result of a change in the key assumptions used to determine the DB pension expense offset by a decrease due to the change in accounting to U.S. GAAP.

The expense for DB pension and post-retirement benefits for 2012 and 2013 is determined in accordance with U.S. Financial Accounting Standards Board's ASC 715. For years 2007 through 2011, the expense is determined based on Section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook. The change to U.S. GAAP results in a decrease in the net pension cost of $2.8 million. Discussion of the affect of the change in accounting from Canadian GAAP to U.S. GAAP is discussed further at Exhibit A2, Tab 4.

Schedule 1 has been provided to show the change in net pension costs from 2011 under Canadian GAAP to 2013 net pension cost under U.S. GAAP.

The DB pension cost is a calculation dependent on a number of factors, including the discount rate used to measure the pension liability, the value of the plan assets, and the rate of return on plan assets. The estimate of the DB pension cost for 2012 and 2013 is based on the same key assumptions finalized at year-end 2011 and used in the preparation of the 2012 net periodic cost, a discount rate of 4.30% and a rate of return on assets of 6.75% for 2012 and 6.50% for 2013.

Sensitivity to Key Assumptions

Since setting this estimate that was used in the forecast, economic conditions have changed. Discount rates have decreased and return on assets through to October have been below 7.0%; the impact will be to increase the net pension costs relative to the forecast. A 100 bps decrease in discount rates will increase the net DB pension cost by $7.0 million; a 100 bps decrease in the return on assets in 2011 will increase the net DB pension cost in 2013 by $5.0 million.

Union is proposing that the DB pension costs to be included in base rates for 2013 be based on the assumptions finalized at year-end 2011, as actual asset returns for 2011 will be available at that time. Based on current market conditions, the discount rate is expected to decrease 60 bps and assuming the assets earn 1.0% in 2011, the net pension cost will increase in 2013 by $8.0 million.

Post-Retirement Benefits

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 the result of the change in accounting to U.S. GAAP.

Defined Contribution Pension

The DC pension costs for 2013 are forecast to be approximately $5.6 million, an increase of $2.8 million from the amount included in rates approved in 2007. Union makes contributions to the DC pension plan ranging from 3.5% to 9.5% of salary, based on age and service of each member. The contributions payable by Union are expensed as pension costs in the period incurred. Approximately $1.1 million of the increase in DC costs is due to increased employer contribution rates of 0.75% in each of 2009 and 2010.

The actual costs incurred by the Company increase each year as the number of employees who participate increase, and age and years of service move up the scale. Table 5 details Union's increasing costs as a result of the increased age, years of service and the corresponding rate of Company contribution. Union anticipates this increasing cost trend to continue for 2012 and 2013. Union estimates a $0.4 million increase in 2012 and $0.3 million increase in 2013 in its DC pension cost. Company contributions to the plan will be escalated based on employee age and continuous service as of the previous year.

Table 5
Defined Contribution Pension Plan

Year	# of Employees	Average Rate of Contribution	Average Age	Average Years of Service	Defined Contribution Pension Expense
2006	874	4.09%	42.69	12.72	$2.6 million
2007	901	4.05%	43.15	13.09	$2.8 million
2008	932	4.26%	43.54	13.33	$3.1 million
2009	947	4.95%	44.27	13.90	$3.7 million
2010	940	5.86%	45.06	14.73	$4.5 million
2011	941	5.97%	45.61	15.19	$5.0 million

4/ PAYROLL/HUMAN RESOURCE MANAGEMENT SYSTEM

The EB-2005-0520 Board-approved Settlement Agreement included Union's plan to contract with a third party vendor for Payroll and Human Resource Management System ("HRMS") services. The plan was accepted as a cost-effective alternative to developing an internal system solution. As proposed, outsourcing was expected to create a number of benefits. The benefits were based on the premise that outsourcing would prevent the need for costly system upgrades; allow internal Human Resource employees to focus on business-related work; and, it allowed Union to leverage the purchasing power of Duke Energy at the time. The plan was also intended to create a significant reduction in Company employees dedicated to the task of processing payroll and maintaining a HRMS database.

However, the third party vendor model proved unsustainable because service level requirements were not fulfilled. Union cannot compromise service levels for Payroll and the HRMS. Service levels must be achieved for Union to meet its statutory obligations; such as those required by the Ontario Pension Act, the Employment Standards Act and the Canada Revenue Agency. Access to accurate and timely information is critical for informed decision-making regarding Human Resource processes; such as workforce planning, compensation, pension and benefits. A comprehensive HRMS database is needed to support business applications; such as Environment, Health & Safety, Accounts Payable and Financial reporting.

The third party contract arrangement did not provide the functionality expected or the flexibility required by a company of Union's size and complexity. For example, manual interventions were required to implement and fulfill Union's Collective Agreement obligations; such as processing wage increases negotiated for unionized employees.

Staff reductions were achieved initially. In June 2006, only two employees were remaining. These employees had accountability for managing this third party vendor relationship. However, these staff reductions were not sustained. Additions to headcount were required to support manual processes that existed with this vendor, conduct quality control audits and, ensure regulatory requirements such as those required by the Canada Revenue Agency, were met. By 2007, a total of 17 employees were assigned responsibility for managing the relationship and performing the Payroll & HRMS functions to meet service requirements. These necessary additions to headcount prevented Union from achieving the anticipated annual salary savings of approximately $1.0 million as highlighted in the evidence filed in EB-2005-0520.

Consequently, a decision was made to terminate the third party vendor arrangement. Union will be sourcing Payroll/ HRMS through a Service level Agreement with Spectra Energy utilizing SAP on a go-forward basis. The adoption of SAP will serve Union well as it has a large IT infrastructure footprint. The number of interfaces and bolt-on system solutions within Union will be reduced with the adoption of an enterprise-wide IT solution. SAP provides the functionality, business application integration and the flexibility required to achieve the regulatory requirements and meet the needs of an organization such as Union.

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. In the test year, costs resulting from the elimination of the third party vendor costs are expected to largely offset the costs associated with the SAP solution. A small savings of $24,000 is forecast for 2013.

5/ WORKFORCE DEMOGRAPHICS

Consistent with the evidence filed in EB-2005-0520, an aging workforce continues to be one of the most significant Human Resource issues facing organizations. Union continues to invest in a prudent manner to ensure a skilled and competent workforce is in place to provide the services expected by its ratepayers, achieve compliance required by the Regulatory framework and ensure the protection of public safety.

This shift in workforce demographics to an increasingly aging workforce suggests a higher volume of retirements will need to be addressed. At Union, 44% of existing employees will be eligible to retire within the next five years. This is even more pronounced in some specific front line roles such as Utility Services where 50% of such personnel will be eligible to retire within the next five years.

As stated in EB-2005-0520, the impact of an aging workforce is especially acute for certain front line technical roles, where it can take up to four years to train a fully competent employee. For the period of 2005 to 2010, a total of 123 new Utility Service Representatives ("USR") were trained. An additional 36 USRs commenced training in 2011.

From a Human Resource perspective, this escalated proportion of "near-retirement" workers requires that significant workforce planning and a proactive replacement plan need to be in place to ensure continuity in the maintenance and operation of a safe and reliable gas distribution system.

Union maintains that the costs resulting from an aging workforce are necessary to ensure it is well positioned to deal with the challenges noted above. However, Union will manage these costs within its proposed budgets.

Reconciliation of Pension Expense
2011 Canadian GAAP - 2013 US GAAP
($ millions)

Line No.		Defined Benefit Pension	Post-Retirement Benefits	Total	
1	2011 Canadian GAAP	35.3	7.9	43.2	/u
2	Transitional Obligation	(1.5)	(1.8)	(3.3)	/u
3	Change in Measurement Date	(0.6)	-	(0.6)	
4	2011 US GAAP *	33.2	6.1	39.3	/u
5	Current service cost	4.0	0.6	4.6	/u
6	Net interest cost	(1.2)	(0.1)	(1.3)	/u
7	Expected return on assets	(6.3)	-	(6.3)	/u
8	Amortization	6.5	1.9	8.3	/u
9	2012 US GAAP *	36.2	8.5	44.7	/u
10	Current service cost	0.9	0.3	1.1	/u
11	Net interest cost	1.8	0.2	2.0	/u
12	Expected return on assets	(2.9)	-	(2.9)	/u
13	Amortization	(1.8)	(1.4)	(3.1)	/u
14	2013 US GAAP *	34.2	7.6	41.8	/u

* US GAAP for Canadian Reporting

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Private and Confidential

October 26, 2011

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Spectra Energy Transmission
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Vancouver, BC
V6E 3P3

Mr. Chuck E. Conlon
Director, Employee and Labour Relations, East
Spectra Energy Transmission
50 Keil Drive North
Chatham, ON
N7M 5M1

Dear Bohdan and 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 - 2011, with an outlook for 2012 - 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 2010 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 – 2011). 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 2010 - 2011 using data from a custom sample of companies ("Comparator Group") participating in Towers Watson's 2010/2011 Salary Budget Survey with revenues between $1B -$5B (approximately half-to-double the revenue of Union Gas). The trend in base salary movement since 2010 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 2012 and 2013 is based on the current environment (i.e., 2010 actual increases and 2011 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 2010, the actual median increase for executive base salaries within the Comparator Group was 3.0%, as compared to the Company's 2010 average actual salary increase of 3.75%. The projected 2011 salary increase for executives is 3.0% in the Comparator Group, resulting in a cumulative market increase of 6.0% from 2010 to 2011. By comparison, the Company's 2011 average salary increase for executives is 2.90%, resulting in a cumulative increase of 6.65% over the same period.

Managers

For 2010, the actual median increase for management base salaries within the Comparator Group was 3.0%, as compared to the Company's 2010 average actual salary increase of 3.11%. The projected 2011 salary increase for managers is 3.0% in the Comparator Group, resulting in a cumulative market increase of 6.0% from 2010 to 2011. By comparison, the Company's 2011 average salary increase for managers is 3.15%, resulting in a cumulative increase of 6.26% over the same period.

Salaried Professionals

For 2010, the actual median increase for salaried professional base salaries within the Comparator Group was 2.9%, as compared to the Company's 2010 average actual salary increase of 2.89%. The projected 2011 salary increase for Production and Technical/ Administrative Support (collectively salaried professionals) is 3.0% in the Comparator Group, resulting in a cumulative market increase of 5.9% from

2010 to 2011. By comparison, the Company's 2011 average salary increase for salaried professionals is 2.85%, resulting in a cumulative increase of 5.74% over the same period.

Unionized Employees

For 2010, 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 2011 wage rate increase for unionized employees is 3.0%.

Forecast Beyond 2011

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. 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.

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 Canadian economy has been recovering at a quicker pace than anticipated, but this growth is expected to moderate. These forecasts continue to align with recommendations we made to Spectra Energy in February, 2011:

Observations and Predictions for Canada:

- The Bank of Canada projects that the economy will *"expand 2.9 per cent in 2011 and 2.6 per cent in 2012. Growth in 2013 is expected to equal that of potential output, at 2.1 per cent."* The Bank states that *"recent economic activity in Canada has been stronger than the Bank had anticipated,"* and that the Canadian economy will return to capacity in mid-2012, two quarters ahead of earlier projections. (Bank of Canada Monetary Policy Report April 2011).
  - The Bank expects inflation to stabilize within its targeted range, noting that "the effects of higher world prices for energy and other commodities on Canadian inflation have been tempered by the appreciation of the Canadian dollar." Inflation is expected to be 2.4% in 2011, very close to target at 2.1% in 2012, and within the 1-3% range thereafter.

- Bank of Montreal's May 4, 2011 report indicates that *"Canada's economy will likely grow 2.9% in 2011 [and] growth should moderate to 2.7% in 2012 in response to an expected stronger dollar, higher interest rates and more restrictive fiscal policy."* (North American Outlook report, May 4th, 2011).

- Toronto Dominion Bank's March 16, 2011 forecast states that the *"outlook is for solid Canadian economic growth of 3.0% in 2011, followed by a slowdown to 2.5% in 2012."* (Quarterly Economic Forecast, March 16, 2011).

Provincial Economic Forecasts

Consensus estimates agree that GDP growth in Ontario is poised to stabilize after a strong manufacturing-led recovery, and as government stimulus spending winds down.

- Toronto Dominion Bank's Provincial Economic Forecast estimates that *"real GDP growth is forecast to clock in at 2.9% in 2011 and 2.4% in 2012."* Two headwinds identified by TD include the strength of the Canadian dollar through 2011, and crude oil prices in the range of US$95-100, which will adversely affect the goods-producing sector in Ontario. (TD, Provincial Economic Forecast, April 4, 2011).

- RBC's projections are slightly more optimistic: *"We forecast Ontario's real GDP to rise modestly to 3.1% in 2011 from 2.8% in 2010, thereby marking the province's best performance since 2002. The even better news is that the losses during the tough recession of 2008-2009 will be fully recovered in the course of 2011, allowing Ontario's economy to enter the expansion phase of the cycle… This expansion will continue into 2012 when a 3.1% growth rate is forecasted."* (RBC, Provincial Outlook, March 2011).

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 2010 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 2010 data, the average incentive target for the Company's executives is 36%, and is consistent with the market median target of 35% 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 2010 data, the average incentive target for the Company's managers is 14%, compared with a range of 10% to 15% at market median for the National comparator group.

Salaried Professionals

Within the National comparator group, approximately 75% of salaried professionals in comparable salary bands are eligible to participate in short-term incentive plans. Based on 2010 data, the average incentive target for the Company's salaried professionals is 8%, compared with 10% at market median for the National comparator group.

OPINION

Base Pay

Based on available forecasts, there is general consensus that the Canadian market will continue to recover at a moderate pace, with the bulk of the growth being driven by natural resource-rich provinces such as Alberta where commodity prices are rising and significant capital expansion is anticipated. This will have a positive impact on the labour market nationally.

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 are consistent with market projections in the Utility and Power Services sector. In relation to the Comparator Group, on an aggregate basis Union Gas' salary increases for 2010 and projected 2011 are competitively positioned.

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
Executives	3.21%	4.75%	2.50%	3.75%	2.90%
Managers	3.59%	3.88%	2.46%	3.11%	3.15%
Salaried Professionals	3.31%	3.51%	2.42%	2.89%	2.85%
Unionized	2.88%	2.97%	2.50%	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	2011E
Utility & Power Services					
Executives	5.8%	5.8%	3.0%	2.5%	3.0%
Managers	5.5%	5.4%	3.5%	2.6%	3.0%
Salaried Professionals [2]	4.2%	4.3%	3.6%	2.6%	3.0%

[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

Filed: 2011-11-10
EB-2011-0210
Exhibit D1
Tab 3
Appendix B

uniongas

SHORT-TERM INCENTIVE PLAN (STIP)

C'2011

INDEX

INTRODUCTION:

Each year the company sets performance objectives aimed at ensuring our continued business success. All employees have the ability to influence our success through a combination of corporate, business unit and individual or team performance measures. The successful achievement of these objectives is rewarded through our Short-Term Incentive Plan (STIP).

STIP is an annual variable pay program that is a part of employees' total cash compensation package (base salary + STIP). STIP target incentive levels vary according to market trends. Employees have the opportunity to exceed the target award level through higher demonstrated performance and corporate results.

STIP PERFORMANCE MEASURES OVERVIEW:

STIP is designed to reward employees who meet or exceed objectives that advance Union Gas' strategic initiatives and corporate values. STIP objectives fall into three major categories:

1. Corporate Performance Measures
2. Business Unit Measures
3. Individual and/or Team Performance Measures

Corporate and Business Unit performance measures are reviewed and established each year. These measures unite employees on common goals and also foster collaborative efforts between business units.

Individual and Team performance measures should be set and mutually agreed to by each employee and their manager. Performance measures are intended to provide focus and clarity to the year's business priorities.

At year-end, performance against each measure will be assessed and a value assigned along a predefined performance continuum.

2011 STIP PERFORMANCE MEASURES AND WEIGHTS:

Measure	*Weight*	*Minimum*	*Target*	*Maximum*
Spectra Energy EPS [1]	20%	$1.45	$1.65	$1.90
SET EBIT [2, 3, 4]	25%	$1,683	$1,744	$1,866
Union Gas EBIT [2]	20%	C$396	C$410	C$439
SET EHS Blended Scorecard	10%	See Appendix 1		
Union Gas Operations Scorecard	10%	See Appendix 2		
Individual or Team	15%	Determined in conjunction with your Business Unit management.		

Note: For unionized employees, the terms of their incentive plan are outlined in their collective bargaining agreement.

[1] On-going diluted earnings per share
[2] Millions
[3] 45% of FX impact from budgeted exchange rate of $1.05 shall be removed for calculating goal performance. Normal on-going asset optimization will be included for calculating goal performance. Represents ongoing Spectra Energy EBIT, excluding DCP Midstream.
[4] EBIT for SET will be calculated on a commodity price neutral basis

Award Achievement Range:

As shown above, each STIP measure is defined with a Minimum, Target and Maximum expected performance result. The achievement range details for all of the various measures are as follows:

Measure	Minimum	Target	Maximum
All STIP Measures (Corporate and Business Unit financials, EHS, Operations Scorecards and Individual/Team Objectives)	50%	100%	200%

NOTE: Achievement of less than 50% on any performance measure will result in a payout of 0% for that measure.

2011 STIP TARGETS BY GRADE LEVEL:

Grade Level	STIP Target as a % of Annual Salary (100% achievement)
14	25% - 30%
13	20% - 25%
12	20%
10 – 11	15%
7 – 9	10%
1 – 6	6%

DETAILED STIP GUIDELINES

STRUCTURE OF YOUR INCENTIVE

- Your incentive payment is determined by multiplying the total achievement percentage by your incentive-eligible earnings.
- Incentive-eligible earnings includes: December 31, 2011 annualized base salary plus actual earnings of: overtime, callout pay and shift differentials if applicable.
- Your incentive opportunity is based on your incentive target, the actual result of each performance measure and the weightings for each of those measures.
- Incentive payments are taxable income.
- In Canada, employees are given the opportunity to direct all or a portion of their incentive payment into their DC account.

STIP ELIGIBILITY GUIDELINES:

WHO IS ELIGIBLE?

- All Union Gas regular full-time and part-time non-union employees are eligible to participate in STIP.

  NOTE: The following "Eligibility Exceptions":

  i. For employees retiring, see "Retirement"
  ii. For employees terminating employment with the Company, see "Termination"
  iii. For employees moving within the Spectra Energy family of companies, see "Company Transfers"

NEW HIRES

- Employees hired into a STIP-eligible role during the calendar year will have any approved STIP payment pro-rated based on their hire date and active time worked in the STIP-eligible role during the calendar year.

JOB CHANGES

- Employees who transfer into a STIP-eligible role during the calendar year will be eligible for a pro-rated STIP award based on the effective date of the job change and active time worked in the STIP-eligible role during the calendar year.
- Employees who are promoted from one STIP target level to a higher STIP target level will receive a STIP payment based on the number of days at each STIP target level.
- Employees who move to a role with a lower STIP target level will receive a STIP payment based on the number of days at each STIP target level.
- All other job changes will be administered as per the terms of the Employment Offer.

COMPANY TRANSFERS

- Employees moving within the Spectra Energy Business Units will be treated as transfers and will remain eligible for STIP during the calendar year the transfer occurs.
- STIP payments will be pro-rated according to the applicable Business Unit measures defined under the Short Term Incentive Plan for each STIP-eligible role held during the calendar year.

SEPARATION FROM COMPANY

RETIREMENT

- Employees who retire during the calendar year will remain eligible for a pro-rated STIP payment for time worked up until their retirement date.
- STIP awards earned in the year of retirement are not included in pensionable income.

TERMINATION

- Employees who voluntarily terminate employment prior to the end of a calendar year (on or prior to December 31) will forfeit any STIP eligibility for that calendar year.
- Employees who voluntarily terminate employment after the end of the calendar year (after December 31) will remain eligible for a STIP award for the preceding calendar year.

DEATH

- STIP payment will be pro-rated based on active time worked during the calendar year.

LEAVES OF ABSENCE

Union Gas recognizes a variety of Leaves of Absence from work. As a general rule for STIP eligibility purposes, employees who participate in a Leave of Absence during a calendar year:

- Are eligible for a pro-rated STIP award while on "Active" payroll status during the calendar year.
- Are ineligible for STIP award while on "Inactive" payroll status during the calendar year.

SHORT TERM DISABILITY (STD)

- When on Short Term Disability (STD) an employee remains on Active payroll status; therefore STIP eligibility continues to accrue while on STD.

LONG TERM DISABILITY (LTD)

- When on Long Term Disability (LTD) an employee moves to Inactive payroll status; therefore STIP eligibility does not continue to accrue while on LTD.

PREGNANCY AND PARENTAL LEAVE OF ABSENCE

- Employees who are absent during the calendar year due to a leave of absence for pregnancy and/or parental leave, will be given up to 52 weeks credit towards their annual STIP entitlement
- Birth Mothers may receive up to 52 weeks credit for STIP entitlement (17 weeks pregnancy leave and 35 weeks parental leave) if the pregnancy and/or parental leave is taken in accordance with the provisions of the Employment Standards Act, Ontario, and the company policy, "Pregnancy, Parental and Adoption Leave of Absence".
- The Non-Birth mother/parent, and the adoptive parents, may receive up to 37 weeks credit for STIP entitlement if the parental leave is taken in accordance with the provisions of the Employment Standards Act, Ontario, and the company policy, "Pregnancy, Parental and Adoption Leave of Absence".
- Periods of absence for pregnancy, parental or adoption leave beyond those provided under the Employment Standards Act, Ontario, will not receive credit for STIP entitlement.

EDUCATION AND PERSONAL LEAVE OF ABSENCE

- Employees who are absent during the calendar year due to an Education Leave or Personal Leave of Absence will be eligible for a pro-rated STIP award based on their actual time worked and Active payroll status during the calendar year.

MILITARY LEAVE OF ABSENCE

- Employees on Military Leave during the calendar year remain eligible for a full STIP award.

BENEFITS

FLEX BENEFITS

- Incentive plan payments will not be used as a basis for determining benefit entitlement for Life Insurance, Sick Pay or Long Term Disability Insurance coverage.

PENSION PLAN

- Incentive plan payments are considered pensionable income across Spectra Energy as follows:

  - For all Pension Choices Plans, STIP payments received during the previous 12-month period from July 1 to June 30 will be included in pensionable earnings for the following calendar year.
    - → For example: STIP payment received during the period July 1, 2009 to June 30, 2010 will be included in pensionable earnings for calendar 2011.
  - For employees in the "Grandfathered" Pension Plan, STIP payments will be included in pensionable earnings and are deemed as received in the year awarded; with the exception of the Westcoast Energy Inc. Employees' Retirement Plan for which STIP is not considered pensionable.
  - Incentive plan payments received after retirement will not have pension deductions taken and will not be included in pensionable income.

EMPLOYEE SAVINGS PLAN (ESP)

- Incentive plan payments are not considered eligible earnings for ESP.

GENERAL

- Provisions of the Short Term Incentive Plan are reviewed annually. Union Gas and Spectra Energy reserves the right to modify; amend; or terminate this Plan at any time. In the event of a dispute, the Spectra Energy Corp Annual Incentive Plan document rules.
- Specific terms and conditions affecting STIP payments, in accordance with Plan principles, may be published from time to time and take precedence over this document.
- Changes may be published in this booklet or as an addendum to the Plan.
- Awards may be reduced or cancelled if a participant has engaged in misconduct with respect to his/her employment or has failed to adequately perform the duties and responsibilities of his/her employment assignment, or for any other reason determined to be appropriate by the President and CEO Spectra Energy or their designate.

Union Gas Balanced Scorecard Overview

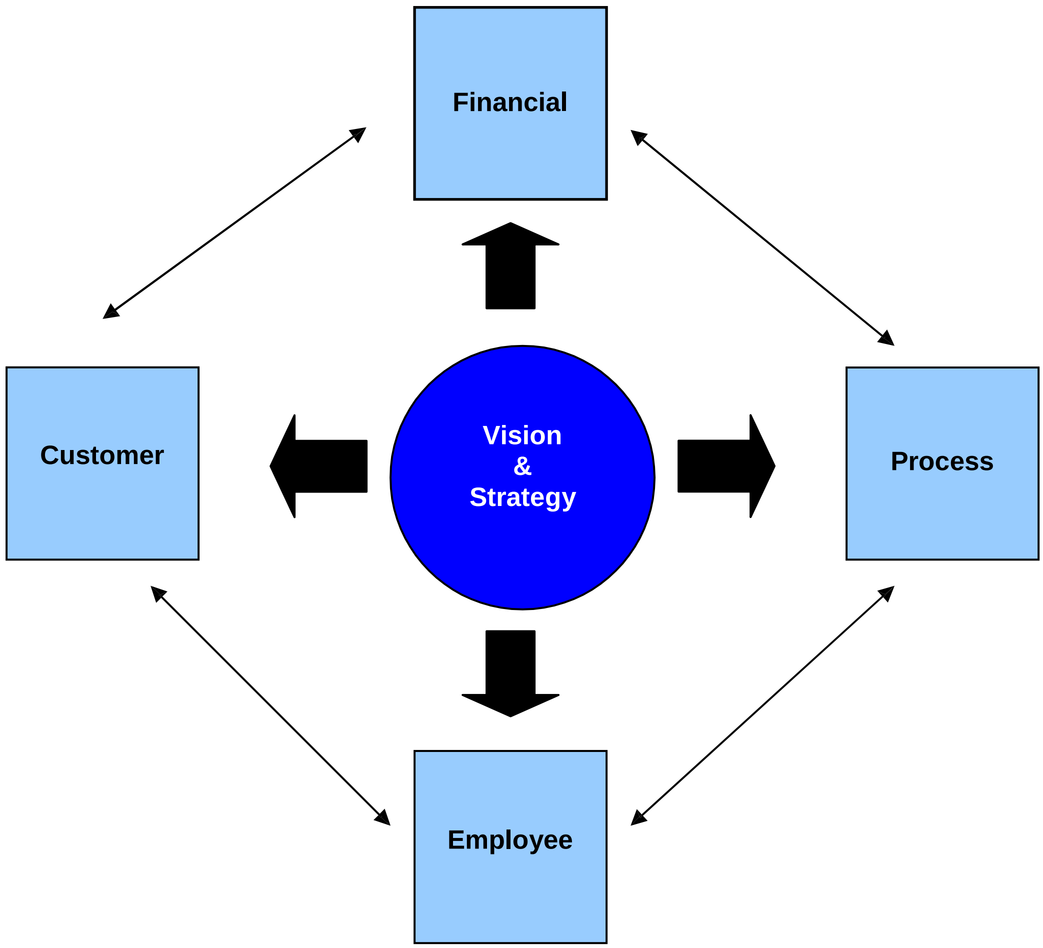
Purpose of Balanced Scorecards at Union Gas

Balanced Scorecards at Union Gas are used to translate strategy into measures with a goal of driving high performance. Scorecards are used by several functional areas within the company.

Structure of the Scorecards at Union Gas

The Union Gas scorecards follow Kaplan and Norton's viewpoint[1] of translating strategy into action through the use of four different perspectives financial, customer, process, and employee. As shown in the graphic below, within each perspective, there is a combination of financial and non-financial measurements. There is also a balance between measures that result from *past* performance and measures that *drive* future performance.

[1] Robert S. Kaplan, Marvin Bower Professor of Leadership Development at Harvard Business School and David P. Norton , Management Consultant and President of the Balanced Scorecard Collaborative, Inc. Kaplan and Norton first introduced the "Balanced Scorecard" in 1992 with an article in the Harvard Business Review. The Balanced Scorecard is a management system that does not only rely on financial information but also non-financial key performance indicators."



1. **Financial Perspective**: The major financial objective for most functional areas within Union Gas is to control costs through increasing productivity and efficiency. Most measurements within this perspective are cost-focused and enable the company to continuously improve its results on these indicators.

2. **Customer Perspective:** Union Gas strives for operational effectiveness in order 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. 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 Gas aspires to continually improve existing internal processes. Certain measures within this perspective have mandatory target levels due to legislative compliance. The remaining measures, such as, Emergency Response, Environmental Spills, Telephone Response, and Mean Time Between Failures, are measured to 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 Gas 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.

Benefits of the Balanced Scorecards at Union Gas

The Balanced Scorecard translates the strategies of the company into measurable indicators that drive performance and efficiency. The financial focus on cost control ensures operational efficiency resulting in lower Operating and Maintenance costs. A customer perspective focused on delivering a reliable, consistent, and cost effective service experience to customers ensures that customers are satisfied at mutually agreeable levels of service and cost. A process perspective focused on the development of consistent and repeatable internal processes ensures that employees remain committed to meeting SQI targets. Finally, an employee perspective focused on creating an environment of high quality and safety ensures a reputation for reliability. The transparency of all the measurements within each perspective drives a focus on continuous improvement which ultimately translates into improved efficiencies throughout the entire company.

Target Setting of the Balanced Scorecards at Union Gas

Measurements are established and evaluated annually in order to drive behaviour and continuous improvement in key areas that align with the strategic objectives of the company. Strategic initiatives are identified annually and stretch targets are incorporated where improvement is necessary to drive long term performance change.

Balanced Scorecard Performance at Union Gas

Union Gas has multiple scorecards, each cascading to the department or district level:

- Distribution Operations
- Engineering, Construction & STO (Storage & Transmission Operations)
- Marketing & Customer Care.

Every scorecard incorporates different objectives, measurements, resulting in a range of total scores throughout the company. Historically, total scores have varied across the groups in the range of approximately 95 to 127 in 2009 and 94 to 137 in 2010. The division of groups and the range of scores throughout the company allows for learning and the identification of best practices specific to each group.

Private and Confidential

October 26, 2011

Mr. Bohdan Bodnar
Vice President, Human Resources Canada
Spectra Energy Transmission
#1100 - 1055 West Georgia Street
Vancouver, BC V6E 3P3

Dear Bohdan:

UNION GAS 2013 RATE APPLICATION - BENEFIT PROGRAMS

This letter report has been prepared for Union Gas ("Union") in connection with its 2013 rate application before the Ontario Energy Board. The report provides information with respect to the competitiveness and costs of Union's employee benefit programs, including pensions, other post-retirement benefits and health and welfare benefits.

Pensions and Benefits Program Design

Over a period of years culminating in 2005, Union designed and implemented a common pension and benefits platform for all employees, including management, salaried and bargaining unit employees. The common platform has been designed to manage program costs, both benefit costs and benefit delivery costs, as well as to facilitate the efficient deployment of human resources.

The common benefits platform was designed to maintain Union's competitive position around the average of a comparator group of companies adopted by Union for the purpose of benchmarking the competitiveness of its pensions and benefit programs. The common benefits platform reflects emerging best practices and incorporates enhanced benefits cost management features, including employee cost sharing.

Union regularly reviews and confirms the competitiveness of its programs, and also regularly reviews benefits costs relative to appropriate industry benchmarks.

Pensions

Union sponsors both defined contribution (DC) and defined benefit (DB) pension plans for all employees. The ongoing pension plan ("Pension Choices") to which newly hired employees are admitted, has both DB and DC components, and covers both exempt and bargaining unit employees. In addition, Union sponsors five legacy DB pension plans which are all closed to new entrants. Each employee participates in only one of the DB or DC pension plans, based on each employee's election at the time of plan enrolment.

Union's cash contributions to the Pension Choices DC plan are expressed as a percentage of pay depending on each participating employee's age and years of service. For this reason, Union's total DC pension cash costs are a function of the covered payroll and employee demographics, and will change in line with changes in these factors. The accounting expense for the DC component of Pension Choices is exactly equal to Union's DC cash costs.

Following a competitive review undertaken in 2008 and 2009, Union confirmed that the Pension Choices DC plan was no longer competitive relative to comparable programs sponsored by Union's peer group. In addition, Union wished to ensure that, on a prospective basis, the DB and DC choices under the Pension Choices plan would continue to be balanced, reflecting known and expected changes in the future economic environment and employee mortality.

For these reasons, Union increased the employer contribution rates under the Pension Choices DC plan by 0.75% of pay effective July 1 in each of the years 2009 and 2010.

The accounting expense for DB pensions is determined in accordance with the standards of the Canadian Institute of Chartered Accountants (CICA), specifically, Section 3461 of the CICA Handbook ("Canadian GAAP"). This is in accordance with the direction of the Ontario Energy Board in 1999. Effective in 2012, Union adopted US GAAP for financial reporting and proposes to use US GAAP for accounting for pensions and other post-employment benefits in the 2013 test year.

Union's DB pension accounting expense under Canadian GAAP has varied significantly in the period from 2007 through 2010. The primary drivers of the levels and changes in DB pension expense between 2007 and 2013 are:

- Historic low levels of long-term government and corporate bond yields. Long-term Government of Canada bonds currently yield around 3.0%, close to 60-year historical lows;

- actuarial losses due to volatile capital market returns in prior periods, particularly the very significant declines in capital markets that occurred in 2008 as a result of the global financial crisis;

- material reductions in pension accounting expense due to significantly increased cash funding contributions to the pension plans by Union, as required by the Ontario Pension Benefits Act; and

- higher ongoing costs and the recognition of actuarial losses due to the adoption of updated mortality tables reflecting significant improvements in retirees' life expectancies.

A number of economic and demographic actuarial assumptions are required to determine the accounting expense for DB pensions. In response to changes in the economic environment, and in accordance with generally accepted accounting principles, Union continues to evaluate economic conditions to determine its best estimate economic assumptions for accounting for DB pensions. In particular, in forecasting the 2013 DB pension accounting expense, the key economic assumptions are the discount rate and the expected rate of return on assets.

The discount rate is used to determine the present value of expected future benefit payments. Canadian and US GAAP require that the discount rate be based on long-term Canadian AA Corporate bond yields, which continually change in line with market interest rates. In determining the rate to be used, Union relies upon bond yield data provided by Towers Watson. In turn, Towers Watson relies upon external, independent sources to assist with developing a yield-curve applicable to Canadian AA Corporate bonds.

The expected rate of return on assets is used to determine the total expected investment return (interest, dividends and capital appreciation) that will be earned by the DB pension fund assets. As the investment return is an offset to the cost of a DB pension plan, the greater the expected return on the pension fund assets, the lower will be the DB pension accounting expense, and vice versa.

Union determines the expected return on assets taking into account the investment policy for the DB pension funds, Towers Watson's economic outlook for capital markets, as well as benchmark data for other similarly situated Canadian organizations. Union has determined that a decrease in this assumption is warranted.

In common with the DB pension plans sponsored by the majority of Canadian organizations, the funded status of Union's DB plans has declined over recent years. In light of the funded status of Union's DB pension plans, as determined in actuarial valuations, and in accordance with the requirements of the Ontario Pension Benefits Act and Regulation, Union has been required to make significantly increased cash contributions to the DB pension funds, over the period since 2007. These additional cash contributions have increased the assets of the DB plans, and the expected rate of return on assets, therefore, is applied against a higher asset base, increasing the expected return on assets and decreasing the pension accounting expense.

The Canadian population continues to experience improvements in longevity due to declining rates of mortality at older ages. This results in significantly increased costs for retirees' pensions and benefits. In determining its benefits accounting costs, Union has adopted updated mortality tables to reflect these improvements. Specifically, for the purpose of the 2013 test year, Union is using 90% of the rates of the Universal Pensioner 1994 ("UP1994") Mortality Table with fully generational projection. In 2007, Union used 100% of the UP1994 rates with rates projected to 2015. The impact of this change in assumption may be demonstrated by noting that the life expectancy of a 65 year old male is 85.5 years under the new table compared to 84.0 years under the prior table. The corresponding life expectancies for 65 year old females under the new and old tables are 87.9 years and 86.6 years, respectively.

Post- Retirement Benefits Other Than Pensions

In 2006, Union completed the implementation of a revised, common retiree benefits platform for all employees, including management, salaried and bargaining unit employees. The new program was designed in response to retiree benefit costs increasing much faster than consumer price inflation, and in order to better manage medical and dental costs and reduce overall benefits delivery costs The new program is a combination of a defined contribution (DC) and defined benefit (DB) program, compared to Union's legacy programs which were entirely DB.

The program comprises a flat dollar amount of life insurance, a DC Health Spending Account and a DB medical plan that contains a number of cost management features, including a significant per person annual deductible ($1,200 per year).

The accounting expense for post-retirement benefits is also determined in accordance with Canadian GAAP. A number of actuarial assumptions are used in determining the accounting expense for post-retirement benefits. In particular, in forecasting the 2013 accounting expense for post-retirement benefits, the key economic assumptions are the discount rate and the health care cost trend rate.

In accordance with generally accepted accounting principles, Union continues to evaluate economic conditions to determine its best estimate assumptions for accounting for post-retirement benefits. The discount rate is used to determine the present value of expected future benefit payments. Canadian and US GAAP require that the discount rate be based on long-term Canadian AA Corporate bond yields, which continually change in line with market interest rates. In determining the rate to be used, Union relies upon bond yield data provided by Towers Watson. In turn, Towers Watson relies upon external, independent sources to assist with developing a yield-curve applicable to Canadian AA Corporate bonds.

The ultimate cost of providing extended health care benefits to retired employees will depend, in part, on how much the cost of medical services increases. The nature and extent of recent and expected medical cost increases in Canada generally, and for Union in particular, are further discussed under "Health and Welfare Benefits, below.

As previously noted under the Pensions section, the Canadian population continues to experience improvements in longevity due to declining rates of mortality at older ages. This results in significantly increased costs for retirees' benefits. While such increases continue to impact retiree benefits under Union's legacy retiree benefit programs, the impact of such increases on the benefits of employees retiring since 2005 has been significantly mitigated by the design of Union's common retiree benefits program.

Health and Welfare Benefits

Union sponsors a flexible benefits program known as Benefit Choices. Benefit Choices is a common platform that applies to all employees, including management, salaried and bargaining unit employees.

The benefits provided under Benefit Choices include:

- Life and accident insurance;
- Short and long-term disability benefits; and
- Medical and dental benefits.

The Benefit Choices program was specifically designed to manage overall costs and to share costs with employees. Employees are provided with flex credits which they use to purchase benefits from a menu of choices. The price tags for each benefit are reviewed each year and adjusted based on claims experience and to maintain Union's target level of employer/employee cost-sharing.

Benefit costs in Canada have increased significantly since 2007. The primary driver of such cost increases has been increases in prescription drug costs which typically account for 60% to 70% of the medical costs covered by employer sponsored plans. A recent Canadian insurance industry study indicated that the average annual increase in prescription drug plan costs in the four year period ending in 2010 was 14.4% per year. The average increases in prescription drug plan costs in each of the prior years have been as follows:

- 2007 - 13.9%
- 2008 - 13.8%
- 2009 - 14.8%
- 2010 - 15.0%

Union has implemented various cost management strategies under the Benefit Choices common platform, including the introduction of an employee drug card to manage prescription drug plan costs. As a result, Union's overall benefit plan costs, while increasing at a much higher rate than consumer price inflation, have increased at rates below Canadian industry. The comparable average annual increase in Union's drug plan costs in the four year period ending in 2010 was 8.0% per year.

For the purpose of forecasting health care costs for active and retired employees in 2013, Union has generally used a health care trend rate of 8.0% per year and a dental care trend rate of 5.0% per year.

Insurance premiums and benefit program administration costs charged by insurance carriers can represent a significant overhead in delivering employee benefit programs. In 2010, Towers Watson assisted Union in conducting a comprehensive insurance marketing to ensure the competitiveness of its programs and rates. This marketing exercise resulted in improved premium rates, guarantees and benefit administration charges.

Employee Savings Plan

Since 2007, there have been no changes to the Employee Savings Plan, The Plan is a voluntary employee savings plan with matching employer contributions dependent on each employee's years of service.

Opinion

Union's pension and benefits costs continue to increase at rates in excess of increases in the consumer price index. The primary drivers of these increases are a continuation of historic low levels of long-term bond yields, poor capital market returns, continuing high levels of medical price inflation and improvements in retiree mortality. None of these factors is unique to Union and, in my opinion and based on my experience, the levels of increases in Union's costs are consistent with the economic environment and in line with increases experienced by other similarly situated employers in Canada.

The accounting estimates discussed herein have been made in accordance with Section 3461 of the Canadian Institute of Chartered Accountants (CICA) Handbook, and with the US Financial Accounting Standards Board's ASC 715, with which I am familiar. The assumptions used were determined by Union management as their best estimates of long-term expectations, after discussions with Towers Watson, and are in accordance with accepted actuarial practice.

In my opinion, for the purposes of the accounting estimates discussed in this letter, the data on which the estimates are based are sufficient and reliable, and the methods employed are in accordance with the requirements of the applicable accounting standards.

Sincerely,

Ashley W. Witts
Account Director

PREFILED EVIDENCE OF

KEN HORNER, SENIOR TAX SPECIALIST

The purpose of this evidence is to discuss Union's income and property tax forecasts. Union's utility 2013 tax forecasts are as follows:

Table 1
2013 Tax Forecast

Line No.	($ millions)	
1	Property tax	$ 64.0
2	Income tax	8.4
3	Total	$ 72.4

INCOME TAX

Union's 2013 income tax expense forecast is comprised of the following:

Table 2
2013 Income Tax Expense

Line No.	($ millions)	
1	Tax on income	$ 23.6
2	Deferred tax drawdown	(15.2)
3	Total	$ 8.4

1/ Forecast Methodology - Tax on Income

Tax on income is calculated by applying the combined federal and provincial tax rate for a given year to taxable income. Taxable income is calculated by adjusting utility income before interest and taxes for interest expense, utility permanent difference and utility timing difference. Only legislated tax rates are used in the calculation of tax on income.

The tax on income calculations are found at; Exhibit D3, Tab 5, Schedule 1; Exhibit D4, Tab 5, Schedule 1; Exhibit D5, Tab 5, Schedule 1 and Exhibit D6, Tab 5, Schedule 1 for the years 2013 through 2010, respectively. The calculation of Capital Cost Allowance ("CCA") is found at Exhibit D3, Tab 5, Schedule 2; Exhibit D4, Tab 5, Schedule 2; Exhibit D5, Tab 5, Schedule 2 and Exhibit D6, Tab 5, Schedule 2 for the years 2013 through 2010, respectively.

2/ Deferred Tax Drawdown

In 1997, Union changed its accounting for income taxes for utility operations from the tax allocation method to flow through tax accounting. The change to flow through tax accounting was adopted for rate-making purposes on a prospective basis in E.B.R.O. 493/494. The tax allocation method of tax accounting used for rate-making purposes prior to E.B.R.O. 493/494 resulted in an accumulated deferred tax balance. 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. The 2013 test year forecast deferred tax drawdown is $15.169 million. The deferred tax drawdown schedule has been provided in Appendix A.

PROPERTY TAX

Union's corporate forecast of its property tax expense for 2013 is $65.4 million. The corporate forecast is then reduced by the property taxes associated with the unregulated storage to arrive at the 2013 utility property tax expense of $64.0 million. The methodology used to determine the property taxes associated with unregulated storage can be found at Exhibit A2, Tab 2.

Forecast Methodology – Corporate Property Tax

Property tax expense consists of two components. The first component is Union's estimated base calendar year tax amount. This amount is added to Union's estimated tax on special/major projects to arrive at its total property tax expense for the 2013 year.

To calculate the estimated base calendar year tax amount, Union applies inflation to its actual total property taxes for Union's facilities paid in the prior year.

Property tax forecasts for special or major projects (i.e. Dawn to Parkway) are separately calculated by forecasting the assessment base and multiplying this base by the tax rate(s) for the specific jurisdictions where these projects are located, adjusted for inflation.

Beginning in 2012, the forecast includes an additional $0.160 million due to a recent Assessment Review Board ("ARB") decision (ARB – June 30, 2011 – File # WR 102472) in Ontario between Enbridge Gas Distribution ("EGD") and the Municipal Property Assessment

Corporation (“MPAC”). This decision changes the property tax classification of odorant injection stations from commercial to industrial, increasing Union’s annual property tax obligations on these stations.

UNION GAS LIMITED

Comparison of Accounting Expenses To Deductions for Tax

2010-2018

Fiscal Year	Accounting Expenses	Tax Deductions	Difference (1)	Tax Amount (2)	Drawdown Utilized	Deferred Tax
2009						(126,929)
2010	(62,700)	26,271	(36,429)	(17,041)	(17,041)	(109,888)
2011	(58,518)	24,765	(33,753)	(15,790)	(15,790)	(94,098)
2012	(55,106)	23,394	(31,713)	(14,835)	(14,835)	(79,263)
2013	(54,564)	22,137	(32,426)	(15,169)	(15,169)	(64,094)
2014	(49,760)	20,978	(28,783)	(13,465)	(13,465)	(50,629)
2015	(48,881)	19,904	(28,977)	(13,556)	(13,556)	(37,074)
2016	(46,909)	18,905	(28,004)	(13,100)	(13,100)	(23,973)
2017	(46,064)	17,972	(28,091)	(13,141)	(13,141)	(10,832)
2018	(43,006)	17,098	(25,908)	(12,120)	(10,832)	(0)

Note:

(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.

PREFILED EVIDENCE OF

KEITH BOULTON, DIRECTOR, ENERGY CONSERVATION STRATEGY

INTRODUCTION

The purpose of this evidence is to summarize the approvals granted to Union in its EB-2011-0327 application for a new Demand Side Management ("DSM") Framework for 2012 to 2014 which was filed on September 23, 2011 and to describe the impacts the EB-2011-0327 application is expected to have on Union's 2013 forecast. Specifically, the Board's EB-2011-0327 Decision provided for:

i) Resource Acquisition, Low-income and Market Transformation Programs for 2012-2014;

ii) Large Industrial Rate T1/Rate 100 Programs for 2012 (Union will apply in 2012 for 2013 and 2014 Programming);

iii) DSM budgets and associated calculation methodology for 2012, 2013 and 2014;

iv) DSM scorecard targets and associated target adjustment methodology for 2012, 2013 and 2014;

v) DSM incentive amounts and associated calculation methodology for the years 2012, 2013 and 2014;

vi) Continuation of the Lost Revenue Adjustment Mechanism (”LRAM”) Deferral Account (“LRAMDA”) and Demand Side Management Variance Account (“DSMVA”);

vii) Stakeholder Terms of Reference; and,

viii) Evaluation Plans.

In addition, within Union’s EB-2011-0025 application for 2012 rates, Union was granted approval to implement the new DSM Incentive Deferral Account (“DSMIDA”).

BACKGROUND

Union has been engaged in DSM since 1997. While DSM based activities produce net bill savings for ratepayers as defined by the Total Resource Cost (“TRC”) test, DSM also has a cost that must be recovered in delivery rates. Union’s total DSM budget is funded by ratepayers. The volume of natural gas saved as a result of DSM activities is eventually reflected in Union’s demand forecast which causes delivery rates to be higher than they would otherwise be. In addition, DSM incentive payments to Union for achieving certain results are recorded in a deferral account and recovered from ratepayers at a later date. Finally, through the LRAM, Union recovers/rebates margin differences which relate to DSM volume savings being different than forecast.

Table 1 details the volumes that have been saved, by customer type, from 1997 to 2010 as a result of Union's DSM activity. It also presents the O&M costs of Union's DSM programs and the corresponding TRC net benefits calculated on the volume savings over this time period.

Table 1

DSM Program Impacts

	DSM Volume Savings (10^3 m^3)[1]				Total ($000s)	
Year	Residential	Commercial	Distribution Contract	Total	TRC Net Benefits [2]	Actual Expenditures
	(a)	(b)	(c)	(d)	(e)	(f)
1997	4,847	2,211	14,027	21,085	$76,294	$2,849
1998	11,780	9,302	6,422	27,504	38,000	3,064
1999	9,410	8,869	12,689	30,968	41,943	3,661
2000	12,681	3,992	15,672	32,345	43,869	4,421
2001	13,233	8,485	26,308	48,026	47,776	3,496
2002	11,622	13,581	17,692	42,895	76,194	3,005
2003	12,459	10,733	15,667	38,859	47,364	3,855
2004	5,430	19,132	34,585	59,147	70,167	5,905
2005	5,062	17,054	42,678	64,794	97,106	8,092
2006	12,416	27,334	50,725	90,475	184,677	12,882
2007	5,605	18,183	32,066	55,854	215,895	16,131
2008	7,838	14,469	39,544	61,851	262,754	20,259
2009	7,263	25,932	59,411	92,606	308,255	22,222
2010	4,949	14,645	101,522	121,116	284,132	21,532
Total	124,595	193,922	469,008	787,525	$1,794,426	$131,374

Note:
(1) 1997 - 2010 are actual volumes (2010 audited pending Board approval).
(2) TRC net benefits are calculated based on the input assumptions in effect for the year considered.

TARGETS AND THE LRAM

Early in 2014, Union will evaluate its actual 2013 DSM performance against its targets as specified by the scorecards approved in EB-2011-0327. It will then submit its Annual Report for audit by an independent auditor in accordance with the Terms of Reference filed in conjunction with the EB-2011-0327 Settlement Agreement. The distribution margins related to the variance between the actual volume savings achieved and the target savings included in rates will be recorded in the LRAMDA.

DSM BUDGET AND THE DSMVA

For 2013, the total DSM budget will be equal to the 2012 budget of $30.954 million, plus inflation as defined by the four quarter rolling average of the GDP-IPI at Q2, 2012. Union proposes to recover these costs in 2013 rates.

Union will record the difference between actual expenditures and the budget included in rates in the DSMVA. Union is eligible to recover up to an additional 15% above its annual Board-approved DSM budget through the DSMVA, subject to the following restrictions:

1. Union has achieved its overall weighted scorecard target on a pre-audited basis for one or more of its scorecards. The DSMVA will be used to produce results against any Program scorecard(s) which have achieved the overall weighted scorecard target.
2. Any incremental funding can only be used on Program expenses (i.e. promotion and incentive costs, not additional utility overheads).
3. The maximum allowable 2012 overspend for the Large Industrial Rate T1/Rate 100 program is $0.764 million, not including inflation (15% of the pre-inflation $5.095 million budget allocated to Rate T1 and Rate 100 customers). It may be

allocated to programming for Rate T1, Rate 100, or any combination, at Union's discretion.

DSM INCENTIVE

Union's maximum DSM incentive amount available for the 2012 program year is $10.450 million. For 2013, this amount will be increased by inflation as defined by the four quarter rolling average of the GDP-IPI at Q2, 2012.

Upon completion of the plan year, the DSM incentive will be calculated and recorded in the DSMIDA.

PREFILED EVIDENCE OF

LINDA VIENNEAU, MANAGER PLANT ACCOUNTING

The purpose of this evidence is to provide the impact of the 2011 Depreciation study and amortization of Regulatory Overhead Assets. The depreciation study can be found at Exhibit D2.

Attached as Appendix A is a summary of the provision resulting from this study. Page 1 of the Appendix provides a summary of the results of the updated provision as compared to the provision using the 2004 rates from the 2003 Updated Depreciation Study filed under RP-2003-0063 Exhibit D2, Tab 2

Pages 2 and 3 of Appendix A provide a more detailed comparison to the RP-2003-0063 study. The provisions from the current study are summarized in columns (a), (b) and (c). These are the same details as provided in Exhibit D3, Tab 4, Schedule 1.

The determination of the provision using the 2004 rates is outlined in columns (d) through (f) of Appendix A. Updated rates resulting from the study can be found in column (b) in Appendix A and correspond to the rates found in Foster Associates Inc. 2011 Depreciation Study, Page 16, Statement A, Column G.

The impacts of the above changes are reflected in column (g) of Appendix A. The updated rates result in a provision for depreciation and amortization of $196.5 million, which represents a decrease of $14.5 million from the amounts using the 2004 rates. For ease of accounting the Communication Structure Assets have been transferred to the Communication Equipment Assets with about a $0.004 million increase in depreciation.

As part of the Union Gas International Financial Reporting Standards conversion project, it was determined that indirect overhead costs (“OH”) are capital within a regulatory environment, but are expensed in an unregulated environment. As a result, OH was no longer distributed to individual assets, but capitalized to a single asset per functional category as Regulatory Overhead Assets. Regulatory Overhead Assets are amortized over the average life of the assets within each functional category that attract overheads. This change was implemented in 2010.

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Depreciation Using Proposed Rates	Depreciation Using 2004 Rates	Variance From 2004 Rates
		(a)	(b)	(c)
1	Total provision for depreciation and amortization before adjustments (per page 3)	198,732	213,282	(14,550)
2	Adjustments: vehicle depreciation through clearing	2,265	2,265	-
3	Provision for depreciation amortization and depletion	196,467	211,017	(14,550)

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31,2013

Line No.	Particulars ($000's)	Average Plant [1]	Proposed Rate (%)	Proposed Provision	Average Plant [1]	2004 Rate (%)	Provision Using 2004 Rate	Variance From 2004 Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Intangible plant:							
1	Franchises and consents	1,321		63	1,321		63	-
2	Intangible plant - Other	6,356		122	6,356		122	-
3		7,677		185	7,677		185	-
	Local Storage Plant							
4	Structures and improvements	3,299	2.85%	94	3,299	3.30%	109	(15)
5	Gas holders - storage	4,574	2.54%	116	4,574	2.68%	123	(7)
6	Gas holders - equipment	13,250	3.54%	469	13,250	3.68%	488	(19)
7	Regulatory Overheads	1,656	30	55	1,656	30	55	-
8		22,779		734	22,779		775	(41)
	Storage:							
9	Land rights	32,062	2.10%	673	32,062	2.23%	715	(42)
10	Structures and improvements	47,792	2.50%	1,195	47,792	2.34%	1,119	76
11	Wells and lines	90,073	2.48%	2,234	90,073	2.66%	2,396	(162)
12	Compressor equipment	235,882	2.68%	6,322	235,882	3.19%	7,525	(1,203)
13	Measuring & regulating equipment	46,275	3.11%	1,439	46,275	4.30%	1,990	(551)
14	Other Storage Equipment	2,302	20.00%	460	2,302	20.00%	460	-
15	Regulatory Overheads	14,664	35	419	14,664	35	419	-
16		469,050		12,742	469,050		14,624	(1,882)
	Transmission:							
17	Land rights	37,846	1.76%	666	37,846	2.00%	757	(91)
18	Structures and improvements	54,602	2.03%	1,108	54,602	2.66%	1,452	(344)
19	Mains	1,078,915	1.98%	21,362	1,078,915	2.37%	25,570	(4,208)
20	Compressor equipment	337,120	3.23%	10,889	337,120	3.52%	11,867	(978)
21	Measuring & regulating equipment	166,532	2.60%	4,330	166,532	3.61%	6,012	(1,682)
22	Regulatory Overheads	44,785	40	1,120	44,785	40	1,120	-
23		1,719,800		39,475	1,719,800		46,778	(7,303)
	Distribution - Southern Operations:							
24	Land rights	7,571	1.65%	125	7,571	1.67%	126	(1)
25	Structures and improvements	129,114	2.22%	2,866	129,114	2.94%	3,757	(891)
26	Services - metallic	113,773	2.81%	3,197	113,773	3.69%	4,199	(1,002)
27	Services - plastic	783,833	2.51%	19,674	783,833	3.18%	24,926	(5,252)
28	Regulators	68,701	5.00%	3,439	68,701	3.30%	2,270	1,169
29	Regulator and meter installations	70,003	2.80%	1,956	70,003	3.51%	2,454	(498)
30	Mains - metallic	414,764	2.83%	11,738	414,764	2.54%	10,535	1,203
31	Mains - plastic	531,747	2.31%	12,284	531,747	2.34%	12,443	(159)
32	Measuring & regulating equipment	38,524	3.66%	1,410	38,524	4.54%	1,788	(378)
33	Meters	226,902	3.82%	8,668	226,902	3.70%	8,395	273
34	Regulatory Overheads	72,124	35	2,061	72,124	35	2,061	-
35		2,457,056		67,418	2,457,056		72,954	(5,536)

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31,2013

Line No.	Particulars ($000's)	Average Plant (1)	Proposed Rate (%)	Proposed Provision	Average Plant (1)	2004 Rate (%)	Provision Using 2004 Rate	Variance From 2004 Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Distribution plant - Northern & Eastern Operations:							
1	Land rights	9,443	1.71%	161	9,443	1.68%	159	2
2	Structures & improvements	62,145	2.41%	1,498	62,145	3.13%	1,945	(447)
3	Services - metallic	96,441	3.22%	3,106	96,441	3.58%	3,452	(346)
4	Services - plastic	374,732	2.60%	9,743	374,732	3.19%	11,954	(2,211)
5	Regulators	27,294	5.00%	1,365	27,294	3.34%	912	453
6	Regulator and meter installations	29,845	2.92%	871	29,845	3.50%	1,045	(174)
7	Mains - metallic	379,283	3.02%	11,454	379,283	2.52%	9,558	1,896
8	Mains - plastic	208,318	2.38%	4,958	208,318	2.35%	4,895	63
9	Compressor equipment	-		-	-	3.34%	-	-
10	Measuring & regulating equipment	110,387	3.77%	4,162	110,387	4.63%	5,111	(949)
11	Meters	65,744	4.03%	2,649	65,744	3.67%	2,413	236
12	Regulatory Overheads	32,523	35	929	32,523	35	929	-
13		1,396,155		40,896	1,396,155		42,373	(1,477)
	General:							
14	Structures and improvements	44,184	1.92%	848	44,184	2.13%	941	(93)
15	Office furniture and equipment	6,405	6.67%	427	6,405	6.67%	427	-
16	Office equipment - computers	101,827	25.00%	25,457	101,827	25.00%	25,457	-
17	Transportation equipment	41,741	13.27%	5,539	41,741	10.07%	4,203	1,336
18	Heavy work equipment	18,649	6.92%	1,291	18,649	4.55%	849	442
19	Tools and other equipment	29,694	6.67%	1,981	29,694	6.67%	1,981	-
20	Communications equipment	15,145	6.67%	1,010	15,145	6.67%	1,010	-
21	Communications structures	225	6.67%	15	225	4.88%	11	4
22	Regulatory Overheads	7,143	10	714	7,143	10	714	-
23		265,013		37,282	265,013		35,593	1,689
24	Sub-total	6,337,530		198,732	6,337,530		213,282	(14,550)
25	Total provision for depreciation and amortization			198,732			213,282	(14,550)
26	Depreciation through clearing			2,265			2,265	-
27		6,337,530		196,467	6,337,530		211,017	(14,550)

PREFILED EVIDENCE OF

DAVE HOCKIN

MANAGER AFFILIATE REPORTING AND ACCOUNTING

The purpose of this evidence is to provide an overview of Union Gas Limited's ("Union") forecast of affiliate charges[1] (for services provided to and received from affiliates) and to demonstrate how these charges meet the Board's "three-prong test" for recovery from ratepayers as described by the Board in the E.B.R.O. 493/494 Decision with Reasons.

The evidence is structured as follows:

1/ Affiliate Services Forecast

2/ Purpose of Shared Services

3/ Cost Allocation Methodology

4/ Benchmarking

5/ Union's Shared Services in Relation to the Three Prong Test

1/ AFFILIATE SERVICES FORECAST

Union forecasts it will have net revenue (services provided by Union to an affiliate minus charges received by Union from an affiliate) for years 2011, 2012, and 2013. Table 1 provides a summary of Union's affiliate services forecast. The attached Schedules 1-3 detail revenue, expense, and net

[1] The contracts Union has with its affiliates for gas supply and S&T services are described at Exhibit A1, Tab 9.

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

Table 1
Affiliate Services Forecast
($ Millions)

Line No.	Functional Service	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast	
		(a)	(b)	(c)	(d)	
	SLA Services (Gross)					
1	Revenue	10.2	11.7	13.7	13.7	
2	Expense	9.1	8.6	9.2	9.4	
3	Depreciation Expense	0.4	0.4	2.3	2.4	
4	Gross Revenue (Expense)	0.7	2.7	2.2	1.9	(Line 1 -2 -3)
5	OH Capitalization	(1.7)	(1.7)	(1.6)	(1.6)	
6	Net Revenue (Expense)	2.4	4.4	3.8	3.5	(Line 4 -5)
7	Unregulated Allocation	0.0	0.2	0.2	0.2	
8						
9	Net Regulated Revenue	2.4	4.2	3.6	3.3	(Line 6 -7)

The affiliate services Union receives are for Union Gas ("the Company"). Affiliate service revenue and expense are allocated to the unregulated portion of Union's operation using the same allocation factors applied to Union's internal operating and maintenance ("O&M") cost.

As shown in line 9 of Table 1, there is a forecasted $0.9 million increase in net revenue in 2013 as compared to the 2010 actual results. This is comprised of a revenue increase of $3.5 million offset by an increase in expense of $2.0 million for depreciation and $0.3 for changes in other expenses over the four-year period.

Depreciation

As shown on Table 1, the only significant variance in expenses from 2010 through 2013 is the fee for depreciation expense. Depreciation is the cost paid to Spectra Energy ("Spectra") for Union's share of amortizing common Information Technology ("IT") systems owned by Spectra and used by all companies. Although referred to as depreciation, this is recorded as an affiliate expense because it is a SLA fee paid to Spectra. Table 2 details the depreciation charge by component.

Table2
Affiliate Depreciation Expense
($000's)

Line No.	IT System	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
		(a)	(b)	(c)	(d)
1	HR	151	146	149	-
2	IT Security	97	94	96	-
3	IT Help Desk	27	26	27	-
4	Portal	100	97	99	-
5	Supply Chain		-	897	897
6	HR		-	511	1,024
7	Internal Controls		-	101	100
8	Treasury, AP, Finance		-	396	423
9	Total	375	363	2,276	2,444

As shown on Table 2, the depreciation cost increase from 2010 to 2012 is a result of new systems coming into service. The decrease in 2013 is the elimination of the charge from systems that came into service in 2008.

The new systems in 2011 relate to Supply Chain (Procurement); and 2012 includes Human Resources ("HR"), Accounts Payable ("AP"), Treasury, Finance, and Internal Controls. The HR information system is the foundation that enables the in-sourcing of Payroll, Internal Controls, and work flow automation for AP. Please refer to the evidence of Mr. Bohdan Bodnar, Ms. Pat Elliott and Mr. Chuck Conlon filed at Exhibit D1, Tab 3 for more information regarding the decision to source the Payroll function through a SLA with Spectra.

The Supply Chain (Procurement) systems were modified to obtain efficiencies through the use of common corporate policies and procedures, common supplier data bases, managing supplier relationships, electronic interfaces with suppliers and, improved linkage to the payment processes.

The AP system is being redesigned to enable automated workflow while also increasing internal controls. The forecast includes additional revenue from Spectra beginning in 2012 as a result of Union starting to process AP for Spectra. Union has been processing AP for all of its Canadian affiliates for more than 10 years.

Union 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.

The Internal Controls application comes into service in 2012 replacing an unsupported data base.

The forecasted depreciation expense includes the Supply Chain system which was modified during 2010 and 2011. The depreciation expense for this system began in 2011 as the system was phased in.

2007 Board-approved and 2013 Forecast Comparison

Subsequent to Union's 2007 rate case (EB-2005-0520) Duke Energy Corporation spun off its natural gas businesses forming Spectra Energy. At that time, Spectra/Union went through significant restructuring. The services and organizational structures of the former Duke and the current Spectra and Union Gas companies changed substantially. Some services provided by Duke were terminated, some re-contracted with third parties, some were transferred to Union, and some were restructured for cost reductions. These changes make it complex and difficult to provide a meaningful comparison of individual services between Board-approved 2007 and 2013 forecast. An aggregate summary of the Board-approved forecast compared to the 2013 forecast is shown in Table 3.

Table 3
Affiliate Services – 2007 Board-approved vs. 2013 forecast
($ millions)

Line No.		2007 Board Approved	2007 Actual	Variance 2007 Actual vs Approved	2013 Forecast	Variance 2013 Forecast vs 2007 Actual	
	SLA Services (Gross)	(a)	(b)	(c)=(c)-(b)	(d)	(e)=(d)-(b)	
1	Revenue	5.7	6.5	0.8	13.7	7.2	
2	Expense	11.9	6.3	(5.3)	9.4	3.1	
3	Depreciation Expense	-	-		2.4	2.4	
4	Gross Revenue (Cost)	(6.2)	(0.2)	6.1	1.9	1.7	(Line 1 -2 -3)
5	OH Capitalization	(4.1)	0.1	4.2	(1.6)	(1.7)	
6	Net Revenue (Expense)	(2.1)	(0.1)	1.9	3.5	3.4	(Line 4 -5)
7	Unregulated Allocation	-	-	-	0.2	0.2	
8							
9	Net Regulated Revenue (Expense)	(2.1)	(0.1)	1.9	3.3	3.2	(Line 6 -7)

2/ PURPOSE OF SHARED SERVICES

Union participates in shared services as a cost effective means to provide utility services to ratepayers. Sharing services enables the Enterprise (defined as all Spectra companies) to pursue economies of scale and scope to have common platforms and processes. Business units benefit through cost reductions passed on to them as well as being able to access business expertise developed elsewhere in the organization. Shared service structures are a practical means of achieving productivity improvements.

There are four types of services:

i) Enterprise Wide Services

Union is both a provider and receiver of similar services. The Enterprise-has staff at Union, Houston and the West to provide the function to the Enterprise. Cross-billing occurs and Union has both revenue and expense for the function. Services in this group include: Environmental Health & Safety ("EHS"); HR which includes Compensation, Management Oversight, Employee Relations, HR Information Systems, Training & Development, Workforce Planning, and Performance Management; Insurance Management; Information Technology ("IT") which includes Senior Management, IT Systems Support, IT Security, Software procurement, IT Architecture and Policy and, Help Desk support; Legal; Supply Chain; and, Tax.

ii) Union is Provider Only

Union provides services to the Enterprise affiliates for this group of services but does not receive similar services for these functions. These provide revenue to Union. Services in this group include: Engineering & Construction ("ECS"); Finance (Pension Accounting, Affiliate Accounting, and Accounts Payable); Government Relations; HR (Payroll); and, Business Development Storage & Transportation ("BDST") which includes Underground Storage, Capacity Planning, Gas Control, and Affiliate Entity Management.

iii) Union is Receiver Only

These services are provided to Union because it does not have the expertise internally. Since Union only pays for a portion of common staffing, these services cost Union less than having full time employees if Union were to staff itself. These services are an expense to Union. Services in this group include: Corporate Services (Travel, Library, Security, Real Estate Support and Emergency Preparedness Planning); ECS (Project Systems & Controls, Risk Management, Materials Procurement/Supply Chain Support); Ethics; Finance (Controller & Treasury); and, S&T Marketing which is within the BDST category.

iv) Depreciation Expense

Depreciation is the cost paid to Spectra for Union's share of amortizing common IT systems owned by Spectra and used by all companies. These are new IT systems as a result of the spin-off of Spectra from the former Duke Energy. These systems are fundamental for Union's utility operations. A single instance of each system was (is being) paid for by Spectra. The amortized cost is shared among the users of the system. The amortization period is five and 10 years. The initial systems were built in 2007 and came into service January, 2008. They are amortized over the five-year period of 2008-2012. In 2010, 2011 and 2012 other projects have and will come into service and will be amortized over five and 10-year periods. These amortization periods reduce the 2013 cost to Union's ratepayers by $2.0 million as compared the four-year period Union uses for its software projects. The Board's Affiliate Relationship Code ("ARC") permits an affiliate to include a return on assets ("ROA") equal to the Union allowed return. Spectra's fee does not include a return component.

Table 4 provides a summary of these four services by group.

Table 4
Affiliate Revenue (Expense) By Type
($ Millions)

Line No.	Functional Service	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast	
		(a)	(b)	(c)	(d)	
1	Union is Provider and Receiver	0.8	2.0	2.7	2.6	
2	Union Provider Only	2.6	3.0	3.9	3.9	
3	Union Receiver Only	(2.3)	(2.0)	(2.1)	(2.2)	
4	Depreciation Expense	(0.4)	(0.4)	(2.3)	(2.4)	
5	Sub Total	0.7	2.6	2.2	1.9	
6						
7	OH Capitalization	(1.7)	(1.7)	(1.6)	(1.6)	
8	Unregulated Allocation	0.0	0.2	0.2	0.2	
9						
10	Net Regulated Revenue	2.4	4.1	3.6	3.3	(Line 5-7-8)

3/ COST ALLOCATION METHODOLOGY

As part of EB-2005-0520, an independent consultant PricewaterhouseCoopers (“PwC”) reviewed Union’s cost allocation methodology and determined that it was reasonable and consistent with the ARC. Union has not changed its cost allocation approach.

Services to and from Union are based on the Receivers’ needs. Union takes a central role in the costing of all services provided to and received by Union. Union examines the budgeted cost, applies cost drivers and adds an indirect cost to calculate the fully allocated cost (“FAC”). Union takes this central role to ensure a consistent application of costing principles and to facilitate the creation of uniform processes and documents.

4/ BENCHMARKING

Appendix A is a Union Gas Benchmarking Analysis Report (dated August 18, 2011) prepared by KPMG. KPMG was engaged to compare Union's net cost of four corporate support functions: HR, IT, Finance, and EHS to a peer group of companies. These functions were selected because they are the largest payments for services purchased from affiliates in 2011. Each purchase exceeds $0.5 million annually. These four functions represent 68% of the services purchased by Union in 2011. As shown on Table 5 (column c), Union provides similar services to other affiliates for these four functions and forecasts a net revenue of $2.2 million in 2011.

Table 5

2011 Benchmarked Services
($ Millions)

Line No.		Revenue	Expense	Revenue Less Expense
		(a)	(b)	(c)=(a)-(b)
1	Hr	2.4	2.1	0.3
2	IT	3.8	1.6	2.2
3	Finance	1.2	1.2	0.0
4	EHS	0.7	1.0	(0.3)
5	Total	8.1	5.9	2.2

Net cost is Union's loaded internal cost plus the cost for services purchased from affiliates minus revenue for services provided to affiliates.

The benchmarking report includes metrics for three types of peer companies: Utilities (Worldwide); Similar Revenue (all Industries World Wide); and Regional (all Industries North

American). The report for EHS was based on a survey by KPMG of North American gas utilities because a comparative data base for EHS was not available.

Benchmarking Results

Union's net cost for the four functions is at or better (lower total cost) than the median compared to benchmarked companies. The executive summary (p.4) of the report states:

> ***Benchmarking Performance summary***
>
> *Finance – Benchmark comparisons indicate that Union has a lower total cost of the finance function as per $1,000 revenue than the majority of the Utility respondents.*
>
> *IT – Benchmark comparisons indicate that Union's IT spend as a percentage of total operating expenses is line with the Utility industry. Note: Total cost of IT function as per $1,000 revenue was not available within industry benchmarks therefore the most suitable alternative cost benchmark was used from Gartner.*
>
> *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 line with the median.*
>
> *EHS –Benchmark comparisons indicate Union's cost of the EHS function per $1,000 revenue is $.97 which is ranked lower than the mean of respondents surveyed.*

5/ UNION'S SHARED SERVICES IN RELATION TO THE THREE- PRONG TEST

The "three-prong test" for recovery from ratepayers as described by the Board in its E.B.R.O. 493/494 Decision with Reasons, includes:

1. Cost Incurrence: Are the costs prudently incurred by, or on behalf of the utility for the provision of a service required by Ontario ratepayers? (i.e. are the services needed?)
2. Cost Allocation: If properly incurred, are the proposed charges allocated appropriately based on the application of cost drivers/allocation factors supported by principles of cost causality?
3. Cost/Benefit: Do the benefits to Ontario ratepayers equal or exceed the costs?

Cost Incurrence Test

In assessing the cost incurrence test during E.B.R.O. 493/494, the Board considered if it was a new service, an additional level or, if it was adequately provided at current levels.

Union has been receiving these shared services for many years. These are services that Union requires. They also replace staffing that Union would otherwise need to provide for or receive in some other manner. If Union did not receive services from an affiliate, Union anticipates its O&M costs would be higher than what has been forecasted for 2013.

Union's affiliate service charges satisfy the Board's cost incurrence test.

Cost Allocation Test

As noted in EB-2005-0520, PwC found Union's affiliate service costing approach to be sound. Unions' methodology for costing and verifying SLA fees has not changed since it was last reviewed by PwC for Union's 2007 rate case.

Union's affiliate service charges satisfy the Board's cost allocation test.

Cost/Benefit Test

In the E.B.R.O 493/494 Decision with Reasons, the Board accepted four categories as the basis for assessing quantifiable benefits:

1. Replacement costs - the services provided replace an equivalent service at equal or lower cost.
2. Synergistic or linkage benefits – the services allow the utility to reduce costs by being part of a larger organization and operating in concert for the procurement of products and services.
3. Revenue enhancement or cost recovery benefits - activities provide value to other affiliates for which payment in cash or in kind is received.
4. Stand alone benefits - strategic actions and activities instituted by the affiliate that produce direct benefits to the utility.

Each of the services Union provides to, or receives from, an affiliate fall into one or more of the categories identified above. In addition, the shared services approach benefits ratepayers by approximately $2.5 million annually as a result of Union billing affiliates for fixed indirect costs.

The services received by Union provide Union with the business knowledge, expertise and capacity to provide and charge for outbound services. For example, common processes, policies and business platforms which are supported with centralized business leadership/governance allow Union to provide services to affiliates.

Union submits the affiliate service charges satisfy the Board's cost/benefit test.

Union Gas Limited
Net Affiliate Revenue (Expense)
($000's)

Line No.	Functional Service	2010 Actual (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)	/u
1	Audit	(501)	0	0	0	
2	Bus Devel, S&T	69	422	499	522	/u
3	Corp Services	(42)	(40)	(43)	(44)	/u
4	Engineering & Contruction	664	309	191	49	/u
5	EHS	167	(282)	(264)	(276)	/u
6	Ethics	(188)	(207)	(220)	(230)	/u
7	Finance	(156)	89	695	665	/u
8	Gov Relations	0	490	671	701	/u
9	HR	(107)	299	467	173	/u
10	Insurance	23	67	50	45	/u
11	IT	921	2,231	2,530	2,610	/u
12	Legal	(120)	(131)	(137)	(143)	/u
13	Other	38	(8)	(9)	(10)	/u
14	Pub Affairs	(25)	(4)	(5)	(5)	
15	Supply Chain	(232)	(728)	(721)	(566)	/u
16	Tax	583	599	744	774	/u
17	Sub Total	1,095	3,104	4,448	4,263	/u
18						
19	Depreciation	(375)	(363)	(2,276)	(2,444)	
20	Grand Total	720	2,741	2,172	1,819	/u
21						
22	OH Capitalization	(1,671)	(1,731)	(1,578)	(1,576)	/u
23	Unregulated Allocation	38	245	196	195	/u
24						
25	Net Regulated Revenue	2,353	4,227	3,554	3,200	/u

Union Gas Limited
Affiliate Revenue
($000's)

Line No.	Functional Service	2010 Actual (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)	/u
1	Audit	206	-	-	-	
2	Bus Devel, S&T	377	607	696	728	/u
3	Corp Services	36	-	-	-	
4	Engineering & Contruction	1,177	702	608	485	/u
5	EHS	705	706	786	821	/u
6	Ethics	-	-	-	-	
7	Finance	1,046	1,247	1,926	1,951	/u
8	Gov Relations		490	671	701	/u
9	HR	2,174	2,357	2,679	2,480	/u
10	Insurance	116	172	150	150	/u
11	IT	2,906	3,814	4,185	4,339	/u
12	Legal	9	11	12	13	/u
13	Other	38	14	13	14	/u
14	Public Affairs	-	-	-	-	
15	Supply Chain	471	540	766	801	
16	Tax	921	1,039	1,174	1,224	/u
17	Total	10,182	11,697	13,667	13,706	/u
18						
19	OH Capitalization	3	-			
20	Unregulated Allocation	256	462	492	503	/u
21						
22	Net Regulated Revenue	9,924	11,235	13,176	13,204	/u

Union Gas Limited
Affiliate Expenses
($000's)

Line No.	Functional Service	2010 Actual (a)	2011 Actual (b)	2012 Forecast (c)	2013 Forecast (d)	/u
1	Audit	708	-	-	-	
2	Bus Devel, S&T	308	185	197	206	/u
3	Corp Services	77	40	43	44	/u
4	Engineering & Contruction	513	393	418	437	/u
5	EHS	538	988	1,050	1,097	/u
6	Ethics	188	207	220	230	/u
7	Finance	1,202	1,158	1,231	1,286	/u
8	Gov Relations		-	-	-	
9	HR	2,281	2,058	2,212	2,307	/u
10	Insurance	92	105	100	105	/u
11	IT	1,985	1,583	1,655	1,729	/u
12	Legal	129	142	150	157	/u
13	Other	-	21	22	23	/u
14	Pub Affairs	25	4	5	5	
15	Supply Chain	703	1,268	1,487	1,367	/u
16	Tax	338	440	431	450	/u
17	Sub Total	9,087	8,593	9,219	9,443	/u
18						
19	Depreciation	375	363	2,276	2,444	
20	Total	9,462	8,956	11,495	11,887	/u
21						
22	OH Capitalization	1,674	1,731	1,578	1,576	/u
23	Unregulated Allocation	218	217	296	307	/u
24						
25	Net Regulated Expense	7,570	7,008	9,622	10,004	/u

Filed: 2011-11-10
EB-2011-0210
Exhibit D1
Tab 7
Appendix A

KPMG
cutting through complexity™

Union Gas
Benchmark Analysis Report

August 18, 2011

ADVISORY

Disclaimer

This presentation is given subject to the written terms of KPMG's engagement. We have indicated in this presentation the sources of the information presented. We have not sought to establish the reliability of those sources.

The presentation and any accompanying analysis pack are provided solely for the benefit of the parties identified in the engagement letter and are not to be copied, quoted, or referred to in whole or in part without KPMG's prior written consent. KPMG accepts no responsibility to anyone other than the parties identified in the engagement letter for the information contained in this presentation.

Contents

Executive Summary (1/2)

Introduction

Union Gas ("Union") has engaged KPMG to benchmark the net cost of the following 4 corporate support functions:

- Finance
- Information Technology (IT)
- Human Resources (HR)
- Environmental Health & Safety (EHS)

Approach

The approach involved mapping Company metrics to standard benchmarking database nomenclature and available benchmarks. The potential metrics were selected based on developing an understanding of Union's activities within the 4 functions. We utilized or collected metrics from respondents within the Utility industry, with similar revenue range (> $1 billion), and similar region (North America) using three sources: APQC benchmarks to compare the Finance and HR support functions, APQC and Gartner to compare the IT support function and primary benchmarking interviews for Environmental Health & Safety (EHS). Where benchmarks were available, we primarily compared cost metrics rather than process efficiency metrics as it was considered more relevant to the scope of this engagement. We compared Union to the 25th percentile, the median, and the 75th percentile of respondents (where applicable).

A Primary Benchmarking approach was used for EHS, as suitable benchmarks were not available in standard databases. This involved engaging a short list of 12 comparable Utilities in North America. Six respondents (including Union Gas) participated in this initiative.

Executive Summary (2/2)

Benchmarking Performance summary

Finance – Benchmark comparisons indicate that Union has a lower total cost of the finance function as per $1,000 revenue than the majority of the Utility respondents.

IT – Benchmark comparisons indicate that Union's IT spend as a percentage of total operating expenses is line with the Utility industry. Note: Total cost of IT function as per $1,000 revenue was not available within industry benchmarks, therefore the most suitable alternative cost benchmark was used from Gartner.

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 line with the median.

EHS –Benchmark comparisons indicate Union's cost of the EHS function per $1,000 revenue is $.97 which is ranked lower than the mean of respondents surveyed.

KPMG has included in this report a graphical summary of results for the selected metrics along with commentary and contributing factors (where applicable) under the heading "observations". Contributing factors were gathered through follow-up interviews with representatives (named in the corresponding sections) from the respective functional areas.

The report includes six sections including: an executive summary, an overview of objectives and approach, benchmarking by function highlighting one overall cost metric for each of the four functions plus a supplemental section that includes additional metrics by function. The report also includes an appendix and glossary of terms.

Overview - Objectives and Approach

Objectives

Union Gas engaged KPMG to evaluate the performance of 4 support functions – IT, Finance, HR, and EHS which will be used to support its rate case that will be presented to the Ontario Energy Board ("OEB") at the end of the 3rd quarter of 2011.

Description of approach

Benchmark Selection – The potential metrics were selected based on developing an understanding of Union's functional activities. This included discussions with the project lead and representatives of each support function, the respective mapping to standard benchmarking database nomenclature, and availability of relevant benchmarks.

Data Collection – Working with the representatives of each support function, we met to review the potential metrics and discuss the accurate alignment of FTEs based on functional processes as outlined in the benchmarking databases. We then provided a metric survey (excel worksheet) to collect data on 2010 costs, FTEs, and other quantitative data elements. Additionally, we also interviewed select staff from each support function to understand current state operating model and processes (where applicable).

Data Validation – Using data workbooks and documentation provided by Union Gas, we reviewed the content given for the purposes of substantiating data inputs to ensure the integrity of benchmarks selected for this engagement.

Data Analysis – We compiled industry benchmarks to compare Union against the Utility industry, comparable revenue range (> 1 billion) and regional respondents (North America) across several measures. The benchmark data was analyzed to identify comparative performance.

Report- The report is organized with a benchmarking by function main summary showing one key overall cost metric for each of the areas examined plus a supplemental section containing additional benchmarking results and commentary.

Benchmarking by function

Finance

Finance Organization Benchmarking Analysis

Summary

Benchmark comparisons indicate that Union is positioned ahead of the majority of utilities in the industry as the Company has a lower total cost of their finance function per $1,000 revenue. Within the similar revenue range and region, Union is ranked between the 75th percentile and the median in comparison with these respondents. Further operational effectiveness metrics are contained in the supplemental section of this report .

Data Sources

We used APQC to provide the benchmark comparisons for Union's Finance function. The following Union Gas personnel assisted in providing data for the benchmarking survey in relation to Finance:

Name	BU/ Department
Dave Hockin	Finance

Finance Organization Benchmarking Analysis

Finance Function Processes Reviewed

The foundation of the APQC's research is the Process Classification Framework (PCF). The PCF organizes operating and management processes into 12 enterprise-level categories, including process groups and more than 1,500 processes and associated activities. Organizations can then discuss an activity and know its exact parameters.

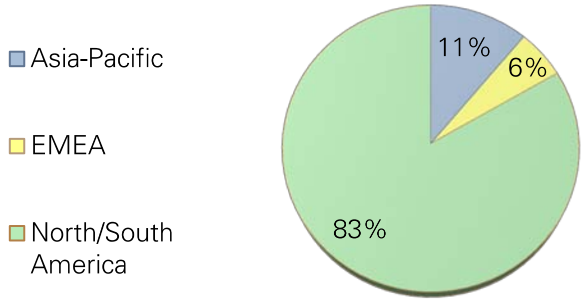
APQC has categorized finance function activities into the following processes:

- Perform planning and management accounting
- Order to invoice
- Manage and process accounts receivables/collections
- Perform general accounting and reporting
- Manage fixed-assets
- Process accounts payable and expense reimbursements
- Manage treasury operations
- Manage internal controls
- Manage taxes

Union has a total of 92.7 finance function FTEs, however not all of the above APQC processes have been included in this analysis or appropriately align with Union's finance function processes. Please refer to the appendix for a breakdown of Union's finance function processes included in this analysis and the number of FTEs allocated to each process.

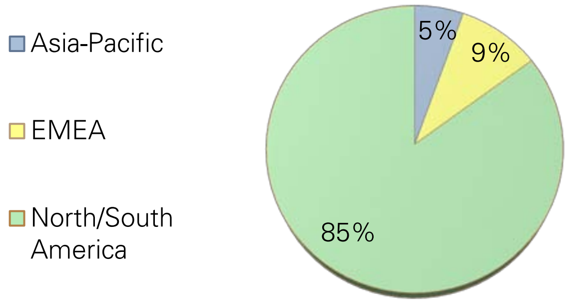
Finance Organization Benchmarking Analysis

Union's performance was evaluated in relation to APQC metrics for the Utility industry, comparable revenue range and regional respondents as described below:



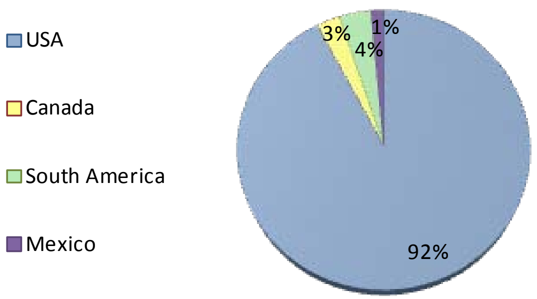
Peer: Industry - Demographics

Within the peer group, "Industry", 83% of respondents are located in a similar region as Union - however the size of the firms within this region is not known.



Peer: Revenue Range - Demographics

Within the peer group, "Revenue Range", 85% of respondents are located in the North or South America that fall in the same revenue category as Union - the industry in which these firms operate is not known.



Peer: Region - Demographics

Within the peer group, "Region", 95% of respondents are located in the US and Canada - the size and industry of these firms is not known.

Finance Organization Benchmarking Analysis

Benchmark: Total cost of the finance function per $1,000 revenue

Use: To evaluate the cost effectiveness of an organization's finance function

Observations:

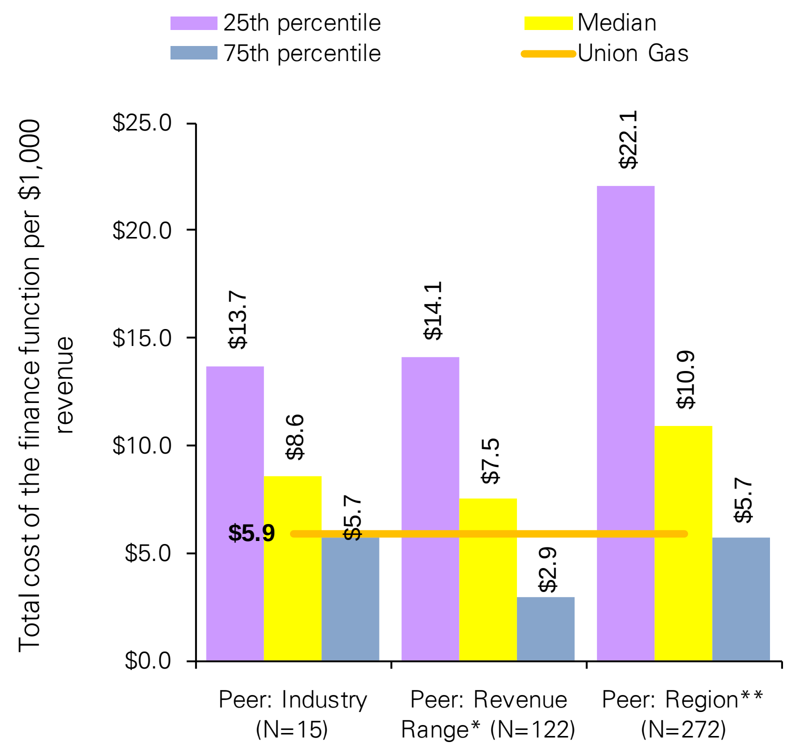
For this benchmark:

- Union is ranked between the median and the 75th percentile in comparison to utility industry respondents. Union has a lower total cost of the finance function as per $1,000 revenue than the majority of the Utility respondents.

- Within the same revenue range and region, Union is ranked between the median and 75th percentile in comparison to these respondents.

Cost Effectiveness

Total cost of the finance function per $1,000 revenue



Source: APQC and Union Gas

** Revenue Range of >$1B*

*** North American Region*

Information Technology (IT)

IT Benchmarking Analysis

Summary

Using Gartner, Union was compared against other utilities in the industry with respect to the metric, measuring a company's IT spend as a percentage of total operating expenses. Due to benchmarking survey limitations, this was the most suitable cost benchmark available for this study. The results demonstrate that Union is reasonable and line with respondents within this space. Additional operational effectiveness metrics are contained in the supplemental section of this report .

Data Sources

We used Gartner and APQC to provide the benchmark comparisons for Union's IT function. The following Union Gas staff assisted in providing data for the benchmarking survey in relation to IT:

Name	BU/ Department
Nancy Penney	IT
Joan Hackett	IT

IT Benchmarking Analysis

IT Function Processes Reviewed

The foundation of the APQC's research is the Process Classification Framework (PCF). The PCF organizes operating and management processes into 12 enterprise-level categories, including process groups and more than 1,500 processes and associated activities. Organizations can then discuss an activity and know its exact parameters.

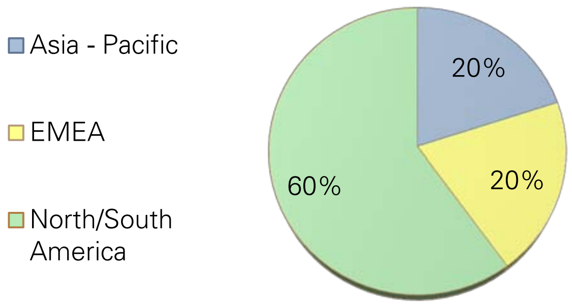
APQC has categorized IT function activities into the following processes:

- Manage the business of information technology
- Develop and manage IT customer relationships
- Manage business resiliency and risk
- Manage enterprise information
- Develop and maintain information technology solutions
- Deploy information technology solutions
- Deliver and support information technology services
- Manage IT knowledge

Union has a total of 119.2 IT function FTEs (excluding contractors), however not all of the above APQC processes have been included in this analysis or appropriately align with Union's IT function processes. Please refer to the appendix for a breakdown of Union's IT function processes included in this analysis and the number of FTEs allocated to each process.

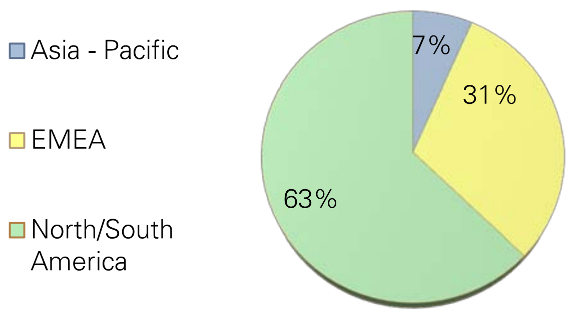
IT Benchmarking Analysis

Where possible, Union's performance was evaluated in relation to the Utility industry, comparable revenue range and regional respondents. Gartner metrics are related to the Utility industry only while APQC metrics are across each of these groups as described below:



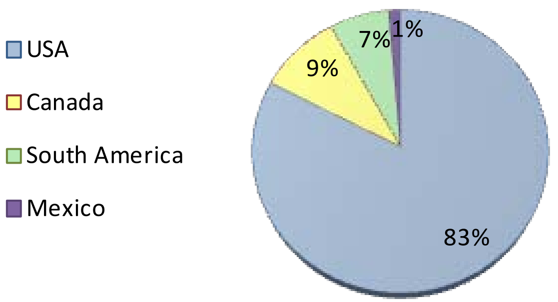
Peer: Industry - Demographics

Within the peer group, "Industry", 60% of the respondents are located in a similar region as Union – however the size of the firms within this region is not known.



Peer: Revenue Range - Demographics

Within the peer group, "Revenue Range", 63% of respondents are located in the North or South America that fall in the same revenue category as Union - the industry in which these firms operate is not known.



Peer: Region - Demographics

Within the peer group, "Region", 91% of respondents are located in the US and Canada – however the size and industry of these firms is not known.

IT Benchmarking Analysis - Gartner Benchmarks

Benchmark: IT Spend[1] as a % of Operational Expense

Use: To evaluate the cost effectiveness of IT

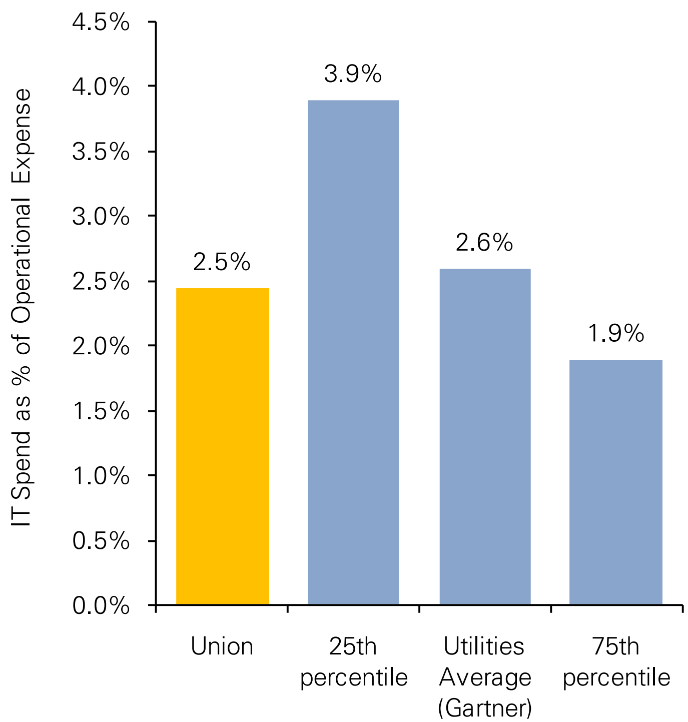
Observations:

For this benchmark:

- Union ranks slightly above the average of utility industry respondents.
- Using Gartner's 'cash-out' definition for IT spend, Union spent a similar amount on IT as a % of revenue in 2010 compared to other utilities.
- Union's IT department is cost centre focused and typically uses outsourced resources for any projects undertaken in place of adding staff internally.

Cost Effectiveness

IT Spend[1] as % of Operational Expense



Source: Gartner, Union Gas
Gartner surveyed approximately 90 Utilities from across the world. The number of utilities that responded to this specific metric was not provided.

[1]*Please refer to Appendix for definition of IT Spend.*

Human Resources (HR)

HR Benchmarking Analysis

Summary

Using APQC, Union was compared against other utilities in the industry with respect to the total cost of their HR function per $1,000 revenue. Results show, Union is positioned ahead of the majority of Utility respondents as the Company. Within the similar revenue range and region, Union is reasonable and in line with the median when compared with respondents surveyed. Additional operational effectiveness metrics are contained in the supplemental section of this report .

Data Sources

We used APQC to provide the benchmark comparisons for Union's HR function. The following Union Gas staff assisted in providing data for the benchmarking survey in relation to HR:

Name	BU/ Department
Chuck Conlon	HR
Bonnie VanBavel	HR

HR Benchmarking Analysis

HR Function Processes Reviewed

The foundation of the APQC's research is the Process Classification Framework (PCF). The PCF organizes operating and management processes into 12 enterprise-level categories, including process groups and more than 1,500 processes and associated activities. Organizations can then discuss an activity and know its exact parameters.

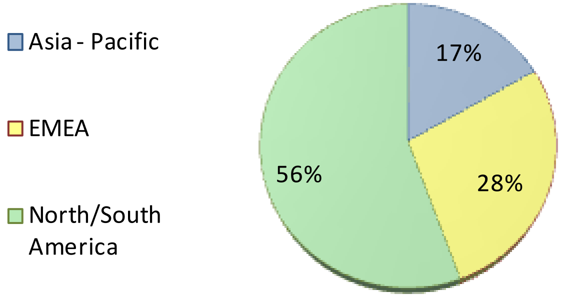
APQC has categorized HR function activities into the following processes:

- Develop and manage human resources (HR) planning, policies, and strategies
- Recruit, source, and select employees
- Reward and retain employees
- Develop and counsel employees
- Redeploy and retire employees
- Manage employee information

Union has a total of 41.4 HR function FTEs, however not all of the above APQC processes appropriately align with Union's HR function processes. Please refer to the appendix for a breakdown of Union's HR function processes included in this analysis and the number of FTEs allocated to each process.

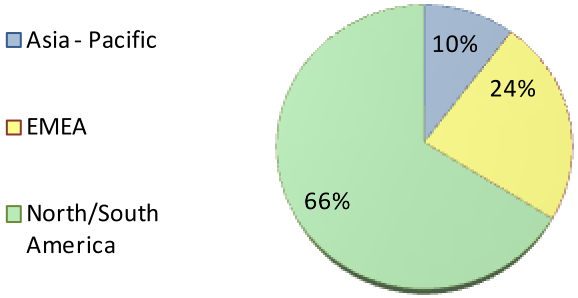
HR Benchmarking Analysis

Union's performance was evaluated in relation to APQC metrics for the Utility industry, comparable revenue range and regional respondents as described below:



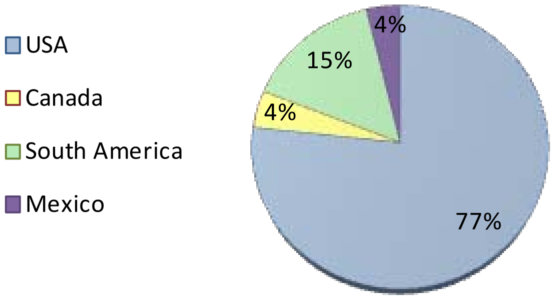
Peer: Industry - Demographics

Within the peer group, "Industry", more than half of the respondents are located in a similar region as Union – however the size of the firms within this region is not known.



Peer: Revenue Range - Demographics

Within the peer group, "Revenue Range", 66% of respondents are located in the North or South America that fall in the same revenue category as Union - the industry in which these firms operate in is not known.



Peer: Region - Demographics

Within the peer group, "Region", 81% of respondents are located in the US and Canada – however the size and industry of these firms is not known.

HR Benchmarking Analysis

Benchmark: Total cost of the HR function per $1,000 revenue

Use: To evaluate the cost effectiveness of HR

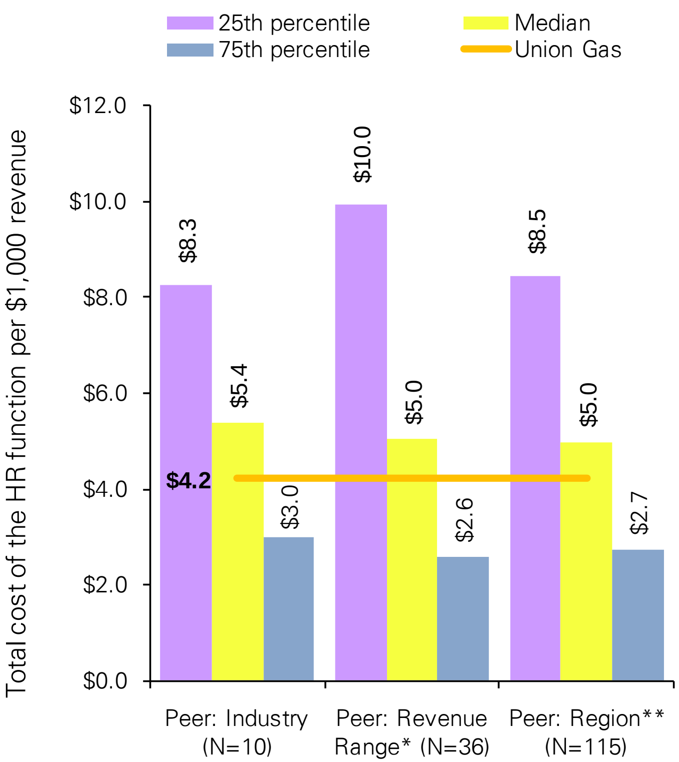
Observations:

For this benchmark:

- Union Gas is positioned between the median and the 75th percentile in the three groups; comparing to utilities in the industry, within same revenue range and region with respect to the cost of HR per $1,000 revenue.

Cost effectiveness

Total cost of the HR function per $1,000 revenue



Source: APQC and Union Gas

** Revenue Range of >$1B*

*** North American Region*

Environmental Health & Safety (EHS)

EHS Benchmarking Analysis

Summary

Using primary benchmarking interviews and questionnaire, Union was compared against 5 other utilities in the industry with respect to the total cost of the EHS function as per $1,000 revenue, total cost of the EHS function per employee and other qualitative factors (please refer to the Appendix for EHS primary benchmark survey results matrix).

Data Sources

We used a primary benchmarking assessment to provide both qualitative and quantitative comparisons for Union's EHS function. The following Union Gas staff assisted in providing data for the benchmarking survey in relation to EHS:

Name	BU/ Department
Paul Greco	EHS

EHS Benchmark Assessment Results

EHS Benchmark Assessment Results[1]						
	Union Gas	**Company 1**	**Company 2**	**Company 3**	**Company 4**	**Company 5**
Benchmark: **1) Cost of EHS Function per $1,000 Revenue** **2) Cost of EHS Function per Employee**	1) $.79 2) $595	1) $1.25 2) $1,143	1) $.36 2) $509	1) $2.61 2) $2,005	1) $2.95 2) $944	1) $.74 2) $433

Benchmark: Total cost of the EHS function per $1,000 revenue

Observations:

- Union's cost of the EHS function per $1,000 revenue is $.79 which is ranked lower than the mean of respondents surveyed $1.45.
- Company 5 and Union are in a similar revenue range ($1-$2 billion). Union's cost of EHS function relative to revenue is in line with Company 5 above.

Benchmark: Total cost of the EHS function per employee

Observations:

- Union's cost per EHS employee is $595. Union's cost is below the mean of $938 when compared to respondents.
- Company 5 and Union have a similar employee base . Union's cost per EHS employee is slightly higher when compared to Company 5. (note: this excludes environmental component in company 5 - which may increase their total EHS cost)

Qualitative Factors:

Observations:

- With respect to a Company's customer strategy, participants surveyed were consistent with a focus on customer, in contrast to Union who is cost focused.
- All respondents including Union have a specific software or system utilized for the EHS function. Of the respondents, 5 out of 6 (including Union) include the cost associated with this software or system as part of their EHS budgets.

[1] Source: Primary Benchmark Surveys and Union Gas

Supplemental Benchmarks

IT
Finance
HR

.

Finance Organization Benchmarking Analysis

Benchmark: Number of finance function FTEs per $1 billion revenue

Use: To evaluate the process efficiency of the finance function

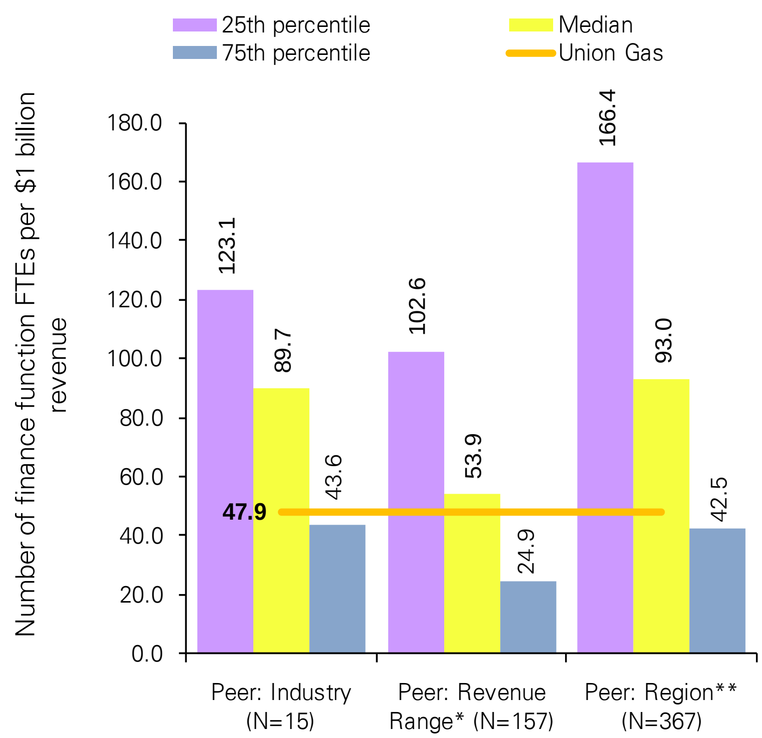
Observations:

For this benchmark:

- Union is ranked between the median and the 75th percentile in comparison to utility industry respondents and to similar respondents in the Company's region and revenue range.

Process Efficiency

Number of finance function FTEs per $1 billion revenue



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

Finance Organization Benchmarking Analysis

Benchmark: Total cost of the finance function per finance function FTE

Use: To evaluate the cost effectiveness of an organization's finance function

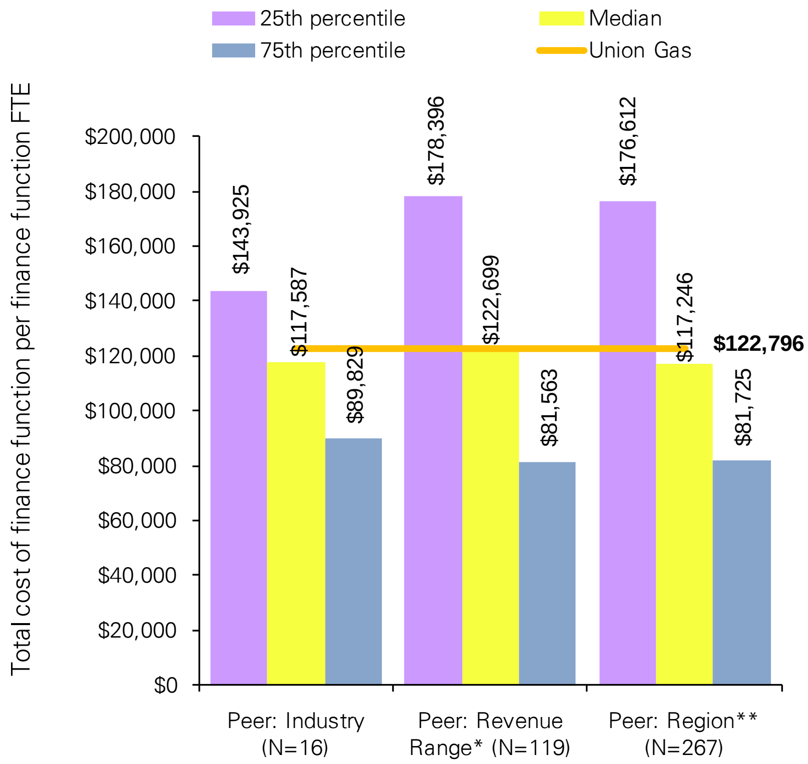
Observations:

For this benchmark:

- Union is ranked between the 25th percentile and the median in comparison to utilities in the industry. Union's has a cost of the finance function of $123K per finance function FTE compared to other utility respondents, median value of $118K.
- Union is in line, and between the 25th percentile and median in comparison to other respondents in the same revenue range and region, respectively.
- Union offers two service lines, Distribution and Wholesale. As a result, given the structure of the Company it does require a degree of specialization within the finance function. This enables the finance function to accommodate the different requirements of each service line.

Cost effectiveness

Total cost of the finance function per finance function FTE



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

Finance Organization Benchmarking Analysis

Benchmark: Number of FTEs for the process group "manage treasury operations" per $1 billion revenue

Use: To evaluate the process efficiency of the treasury function

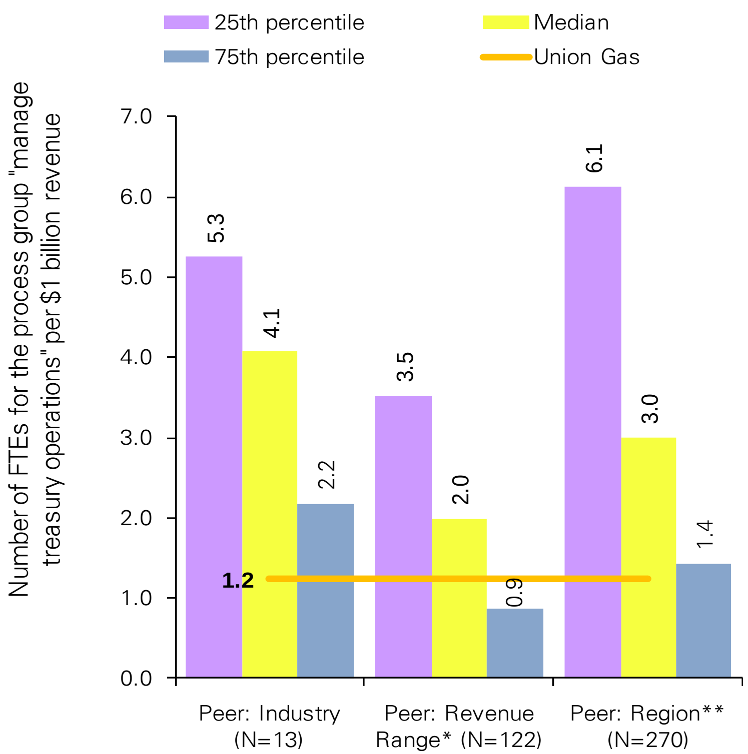
Observations:

For this benchmark:

- Union is ranked above the 75th percentile in comparison to other utilities in the industry and to similar respondents in the Company's region.
- Within the same revenue range, Union Gas is .2 lower the 75th percentile and notably higher than the median.
- Union's Treasury operations performs two main activities, cash management (i.e. oversight of funds) and efforts associated with lenders.

Process Efficiency

Number of FTEs for the process group "manage treasury operations" per $1 billion revenue



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

Finance Organization Benchmarking Analysis

Benchmark: Percentage of finance function FTEs allocated to the process group "manage treasury operations"

Use: To evaluate the size of the treasury function relative to the finance function

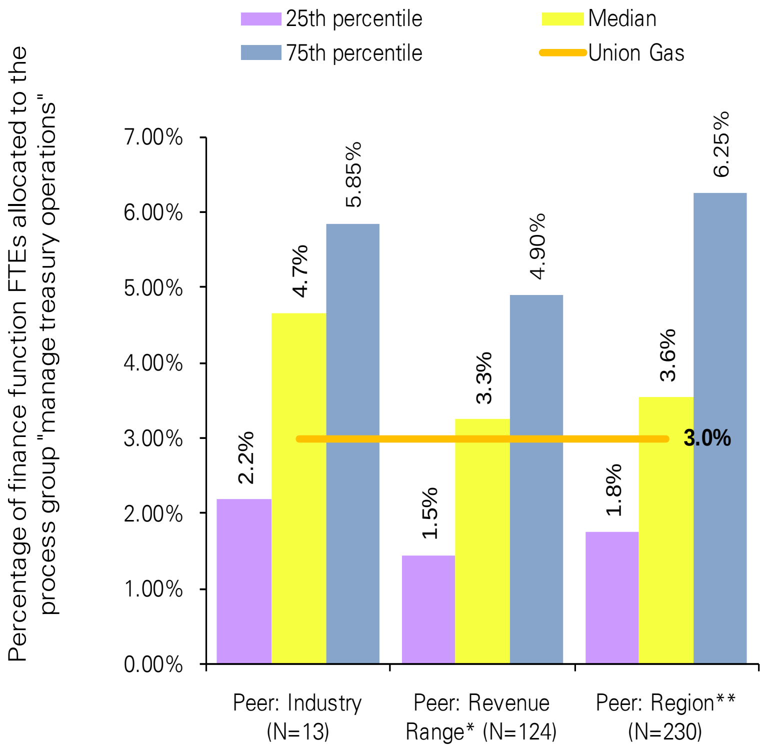
Observations:

For this benchmark:

- Union is ranked between the 25th percentile and the median in contrast to utilities in the industry and to respondents within a similar revenue range and region.
- Union appears to have a low percentage of FTEs allocated to the process group "manage treasury operations" relative to the total number of finance function FTEs in comparison to utility respondents.

Supplemental Information

Percentage of finance function FTEs allocated to the process group "manage treasury operations"



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

IT Benchmarking Analysis

Benchmark: Percentage of total IT FTEs that are external service providers

Use: To evaluate the organizational effectiveness of IT

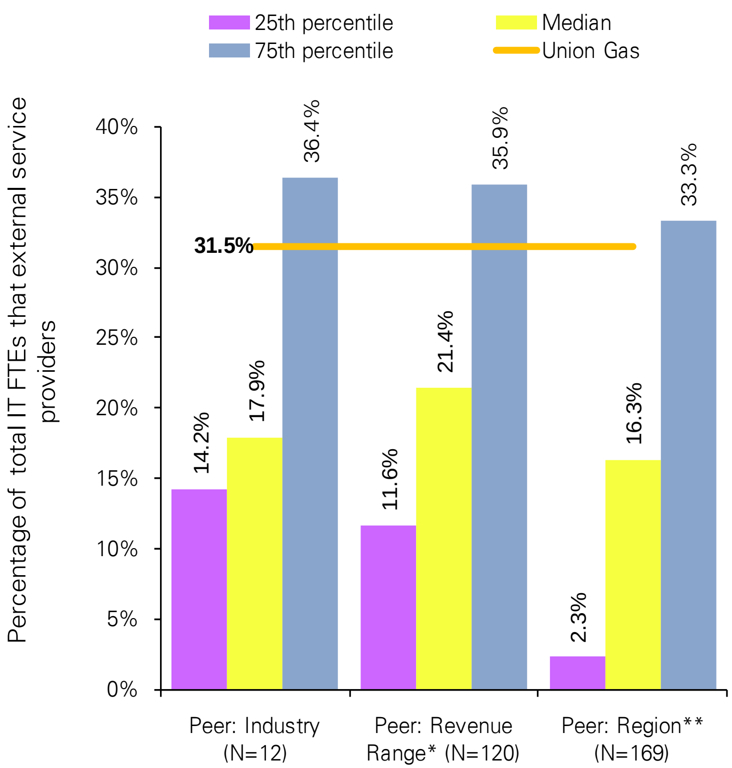
Observations:

For this benchmark:

- Union is ranked between the median and the 75th percentile in comparison to utilities in the industry, regional and similar revenue range respondents.
- Contractors are used to compliment Union's internal staff depending on varying workloads throughout the year and the relative size of IT projects initiated. Union engages in 3-4 major projects (i.e. change initiatives) and generally 30-40 smaller projects (i.e. system application projects) per year.

Organizational Effectiveness

Percentage of total IT FTEs that are external service providers



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

IT Benchmarking Analysis

Benchmark: Number of IT customers serviced per IT FTE

Use: To evaluate the staff productivity of IT

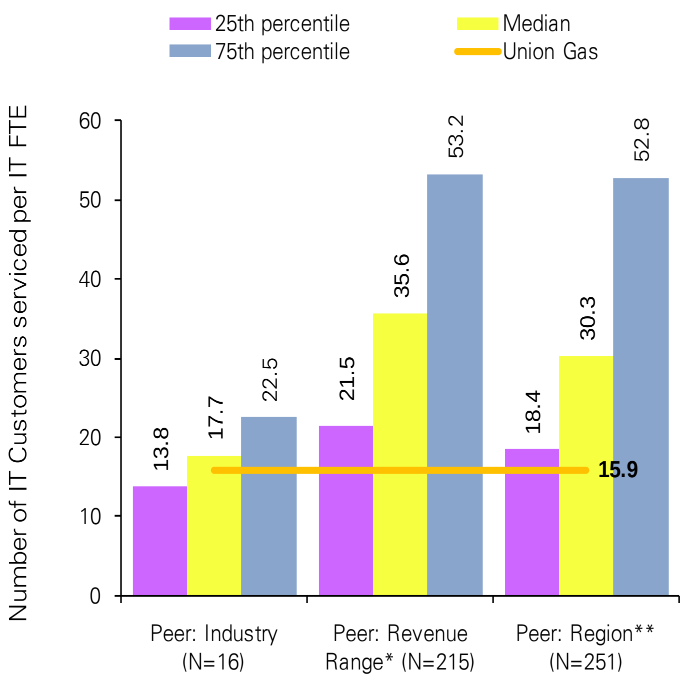
Observations:

For this benchmark:

- Union's IT resources serve approximately 1.8 fewer IT customers per FTE than the utility industry median.
- Within the same revenue range and region, Union is ranked lower than the 25th percentile in contrast to these respondents.
- Union's IT department staff service Union's two business lines; Distribution and Wholesale. Therefore, IT personnel may handle a variety of queries and IT development requiring a depth and breadth of knowledge and effort.

Staff Productivity

Number of IT customers serviced per IT FTE



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

IT Benchmarking Analysis

Benchmark: Total IT cost per FTE

Use: To evaluate the cost effectiveness of IT

Observations:

For this benchmark, Union is ranked:

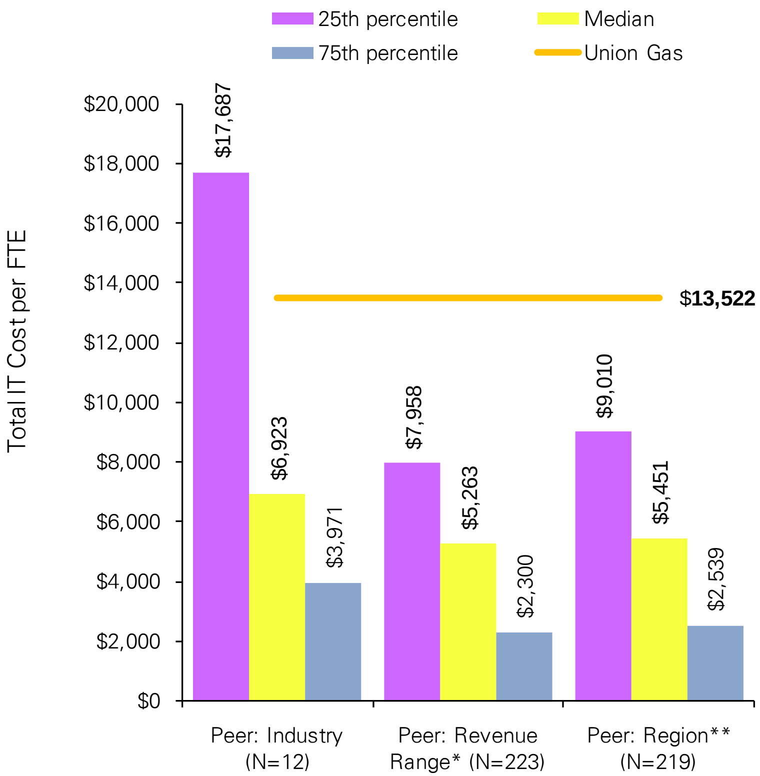
- Between the 25th percentile and the median in comparison to utility industry respondents.
- Within the same revenue range and region, Union is ranked lower than the 25th percentile in comparison to these respondents.

Contributing factors to the higher IT cost per FTE:

- Union offers two different business lines (Distribution and Wholesale services). This structure leads to duplication of IT systems (CIS and billing systems). These systems are managed by IT personnel, hence, it requires additional resources necessary to manage these systems.
- Historically, Union has not purchased standardized applications as a means to update. It has maintained a practice of customizing applications on their legacy systems which often requires a high degree of development and coding effort.

Cost Effectiveness

Total IT cost per FTE



Source: APQC and Union Gas

** Revenue Range of >$1B*

*** North American Region*

HR Benchmarking Analysis

Benchmark: Total personnel cost[1] of the HR function per employee

Use: Compare personnel cost efficiency of the HR function

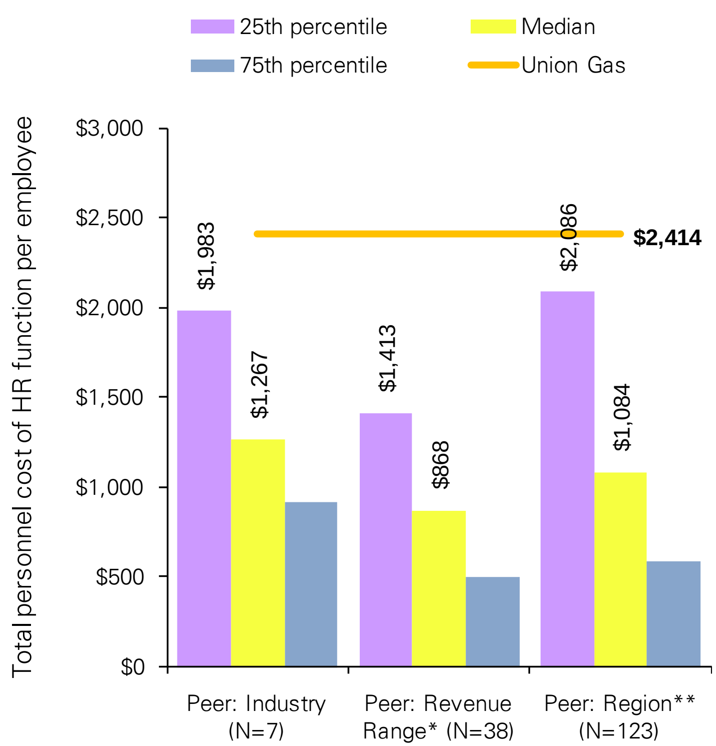
Observations:

For this benchmark:

- Union Gas is ranked below the 25th percentile in comparison to utilities in the industry.
- Within the same revenue range and region, Union's personnel cost of the HR function per employee is higher than the median by $1,761 and $1,545, respectively.
- Union's HR department services two business lines; Distribution and Wholesale with geographic dispersion across Ontario. Therefore, additional staff is be required to service diverse needs and customize programs.
- Union's HR group is comprised of an experienced and long standing service team that is remunerated accordingly, which may lead to higher personnel costs. The benefit from this experience has been deemed by Union as valuable to the business and HR function.

Cost effectiveness

Total personnel cost[1] of the HR function per employee



Source: APQC and Union Gas

** Revenue Range of >$1B*

*** North American Region*

HR Benchmarking Analysis

Benchmark: Total HR cost per business entity FTE (excludes benefit program costs)

Use: Compare the cost efficiency of the HR function

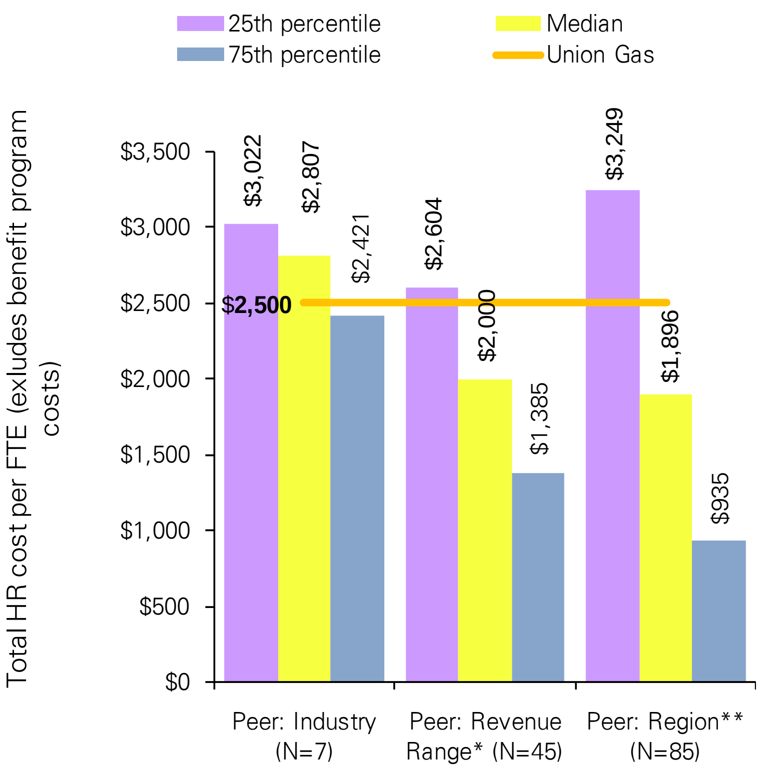
Observations:

For this benchmark:

- Union Gas is ranked between the 75th percentile and the median in comparison to utilities in the industry. Union is lower than median respondents by a cost of $307 per FTE.
- Within the same revenue range and region, Union is positioned between the 25th percentile and median in comparison to these respondents.

Cost effectiveness

Total HR cost per business entity FTE



Source: APQC and Union Gas
** Revenue Range of >$1B*
*** North American Region*

HR Benchmarking Analysis

Benchmark: Total personnel cost[1] of the HR function per $1,000 revenue

Use: To evaluate the cost effectiveness of HR

Observations:

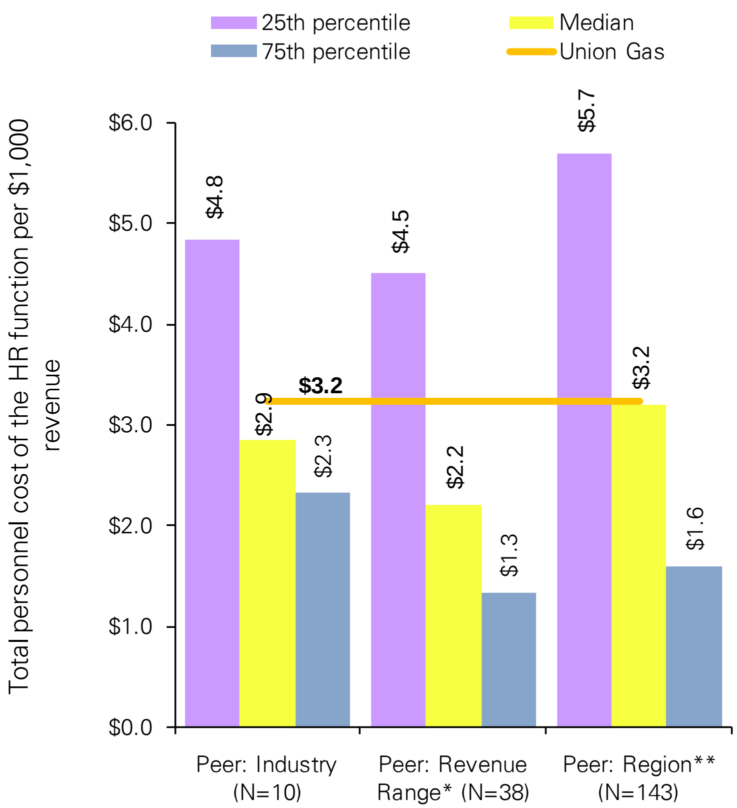
For this benchmark:

- Union Gas is ranked between the 25th percentile and the median in comparison to utilities in the industry. Union's HR personnel cost per $1,000 revenue is greater than the median by a nominal amount of $.3.

- Within the same revenue range and region, Union is below the median and is in line with the median, respectively, in comparison to these respondents.

Cost effectiveness

Total personnel cost[1] of the HR function per $1,000 revenue



Source: APQC and Union Gas

** Revenue Range of >$1B*

*** North American Region*

Appendix

Benchmarking – Key Inputs

Support Function Data

FTEs

- Total Union Gas FTEs: 2,587 (includes overtime hours)
- Total Union Gas Employees: 2,375
- IT Users: 2,767 (each staff member is considered an IT User)

APQC Data Inputs: HR FTEs

Human Resource Process Group	FTE
Create and manage human resources (HR) planning, policies, and strategies	6.6
Recruit, source, and select employees	5.5
Develop and counsel employees	5.5
Reward and retain employees	18.6
Re-deploy and retire employees	0.7
Manage employee information	4.5
Total HR function FTEs	41.4

APQC Data Inputs: Finance FTEs

Finance Process Group	FTE
Manage policies and procedures	52
Perform general accounting	35
Manage treasury operations (Process Group)	2.4
Operate controls and monitor compliance with internal controls policies and procedures	3.3
Total Finance function FTEs	92.7

Benchmarking – Key Inputs (2)

APQC Data Inputs: IT FTEs

Component Description	FTE Count	Contractor Count	External Contractor Count
IS	85.20	14.9	
ITI	42.33	4.33	34.83
Tech Services	9.00		
SAP Services	8.50	0.5	0.06
SAP Services - Affiliate	-2.00		
Vertex Technical Services			0.25
IS Management Group-Houston	1.30		
A139-Support Email, Filenet,EPASS, Supply Chain	0.40		
GT51-Support of HR Systems	0.80		
A140-IT Security	2.30		
GT50-Support Treasury, Finance, Tax	0.40		
ITI West - Security - with Direct Loads	0.30		
ITI West - Bus Mgmt - with Direct Loads	1.40		
ITI Mgmt	-1.63		
Web Wintel	-3.40		
Unix, Data Mgmt, Sys Mgmt, P&C	-9.31		
Security - Control Systems	-0.98		
Security - Admin	-1.85		
CTS, Desktop Delievery, AD/Exchange	-1.92		
Telecom - Data, Voice, Radio, Firewall	-6.89		
Business Management	-3.19		
IT Governance	-0.38		
HR Sustainment	-1.00		
HR Database Support	-0.11		
FACSYS Support	-0.02		
Total IT Net Costs	**119.24**	**19.73**	**35.14**

EHS Benchmark Assessment Results

EHS Benchmark Assessment Results

	Union Gas	Company 1	Company 2	Company 3	Company 4	Company 5
Coverage	• North America	• United States	• North America • EMEA	• North America • South America	• North America	• North America
Net Sales ($B)	• $1.9B	• $3.2B	• $9.2B (NA)	• $14.2B	• $576M	• $1.2B
Customer Strategy	• Cost Leadership	• Customer Focus	• Customer Focus	• Customer Focus	• Combination - Customer focus & Product/Service Differentiation	• Customer Focus
Employee Base (Dependant Contractors)	• 2,587	• 3,500 (500)	• 6,482 (323)	• 18,656 (9,067)	• 2,000 (seasonal - not significant)	• 2,000
EHS Department Structure	• Corporate department	• Corporate department/ Field department	• Corporate department/ Field department	• Corporate department/ Field department	• Corporate department/ Field department	• Corporate department/ Field department

EHS Benchmark Assessment Results

EHS Benchmark Assessment Results

	Union Gas	Company 1	Company 2	Company 3	Company 4	Company 5
EHS Activities	• Developing Standards & Guidelines • Providing Oversight (adherence to standards and reporting) • Initiatives and Projects	• Developing Standards, Guidelines & Methodologies • Providing Oversight • Issuance of Statistics & Tracking Trends • Facilitating & Monitoring Company Initiatives	• Provide Strategic Direction & Manage Local Practitioners • Developing Standards & Guidelines • Manage Company- wide Initiatives & Applications • Monitor & Report KPIs • Conduct Investigations & Audits	• Corporate EHS Services • DEI • Scientific Services • Nuclear Development & Support • Business Planning/Project Management • Systems & Reporting • Corporate Support/ EHS Audits • EHS Field Support • Environmental Subject Matter Expert (SME) • Meteorology • H&S SME	• Developing Standards & Guidelines • Providing Oversight • Hazard Assessments • EHS Audits • Health and Safety Advisors – (internal consulting role) • Operating Staff -- Accountable for Performance (both positive and negative performance)	• Developing Standards & Guidelines • Providing Oversight • EHS Audits • Provide Safety Management Training • Liaison with Regulators • Health & Wellness Program • Public Interaction (i.e. with unions)

EHS Benchmark Assessment Results

EHS Benchmark Assessment Results

	Union Gas	Company 1	Company 2	Company 3	Company 4	Company 5
EHS Cost Allocation	• Total cost -- $1.54M allocated: • Staff & Expenses – $539K • EHS Services Labour Allocation – $356K • EHS Audits & Consulting -- $156K • EPASS --Labour, Software, Temp Staff – $489K	• Total cost -- $4M • Costs allocated evenly across 4 regions , not by activity	• Total cost – $3.3M • Including Salary & Benefits – $2.5M	• Total cost – $37.4M • Scientific Services – $7.5M • Nuclear Support – $500K • Business Planning/Project Management --$700K • Systems , Reporting & DEI – $13M • EHS Support/Data Analysis/ Audits – $3.6M • Environmental Subject Matter Expert – $8M • H&S SME– $3.2M • Miscellaneous -- $2M	• Total cost – $1.7M allocated below: • Staff Regulatory --$700K • Support/Hygienis t -- $300K • Audits/Consulting Costs & Special Projects -- $675K	• Total cost – $870 • Program Development & Training – $261K • Audits – $174K • Developing Guidelines & Standard s-- $174K • Investigate & Reporting – $174K • Public Education & Contractor Database -- $87K
EHS Resource Allocation:	• Total – 6 EHS staff who are evenly allocated to activities below: • Developing Standards & Guidelines • Providing Oversight • Initiatives and Projects	• Total – 14 EHS staff allocated as follows: • Environmental -- 5 • Safety -- 7	• Total – 12 EHS staff: • Strategic Direction & Manage local field staff-- 3 • Developing Standards & Guidelines -- 1 • Manage Initiatives & Applications –7 • EHS Audits – 1 • Monitor/Report KPIs (embedded)	• Total EHS Staff– 202 • Scientific Services – 60 • Nuclear Support – 3 • Business Planning/Project Management – 3 • Systems , Reporting & DEI --59 • Support/ EHS Audits – 10 • Environmental Subject Matter Expert (SME) – 47 • H&S SME– 20	• Total -- 7 EHS staff: • Regulatory (permits/approvals) -- 3 • Industrial Hygienist --1 • Support Field Group/Develop Standards & Oversight) -- 2 • EHS Director -- 1	• 6 EHS staff: • Program Development & Training – 30% • Audits – 20% • Developing Guidelines – 20% • Investigate & Reporting – 20% • Public Education & Contractor Database -- 10%

EHS Benchmark Assessment Results

EHS Benchmark Assessment Results

	Union Gas	Company 1	Company 2	Company 3	Company 4	Company 5
EHS Support Software	• EHS system/software utilized is charged to EHS function • Total cost $1.5M in capital/year and $455K O&M/year	• SAP and SharePoint • Costs allocated to overall firm budget	• Analytix HSE (tracks incidents & injury) • CyberRegs (Search & Monitor Regulations) • Enablon (Carbon footprint tracking) • CMO Compliance (record keeping & auditing protocols) • $130K/yr included in EHS budget ($100K included in IS capital budget)	• eTrac • Total EHS Cost of Annual license = $460K	• Subscription to software – contractor management and incident management • Total EHS Cost = $40K/year	• Spot (provides online tracking of incidents)
Key Metrics: **1) Cost of EHS Function per $1,000 Revenue** **2) Cost of EHS Function per Employee**	1) $.79 2) $595	1) $1.25 2) $1,143	1) $.36 2) $509	1) $2.61 2) $2,005	1) $2.95 2) $944	1) $.74 2) $433

Benchmarking – Glossary of Terms

Full-time Equivalent (FTE) - To calculate the number of full-time equivalents employed during the year for each respective process or activity, you must prorate the number of employees and the hours spent performing each process/activity. Assume that a full-time worker represents 40 hours per week. Provide the average number of full-time equivalents employed during the year for each respective process. Include full-time employees, part-time employees, and temporary workers hired during peak demand periods. Allocate only the portion of the employee's time that relates to or supports the activities identified for an applicable process. Prorate management and secretarial time by estimating the level of effort in support of each activity, by process.

Full-time Employee - For the purpose of this survey, a regular full-time employee is hired for an indefinite period of time and is normally scheduled to work forty hours per week.

Appointment is continuous, subject to satisfactory performance and availability of funding.

Personnel Costs - Personnel cost is the cost associated with personnel compensation and fringe benefits of employees (i.e., those classified as FTEs which includes both full-time and salaried/hourly employees e.g. part-time, contractors) contributing to each respective process. Personnel cost should include all of the following costs.

Employee Compensation: Includes salaries and wages, bonuses, overtime and benefits.

Fringe: Includes contributions made towards the employees' government retirement fund, workers compensation, insurance plans, savings plans, pension funds/retirement plans, and stock purchase plans. This should also include special allowances, such as relocation expenses and car allowances.

IT Spend - Gartner defines IT Spend as the 'cash out of the business' amount related to IT. Therefore, capital costs are included and depreciation is not. APQC defines IT Spend as the 'operating expense' of IT. In this case, capital costs are not included and depreciation is included.

PREFILED EVIDENCE OF

TANYA BELL, PUBLIC AFFAIRS COMMUNITY INVESTMENT SPECIALIST

TOM ARNOLD, DIRECTOR COMMUNICATIONS AND COMMUNITY INVESTMENT

The purpose of this evidence is to provide an overview of Union's community investments and its proposal to recover the costs associated with these investments.

Union has a longstanding commitment of investing in the communities in which it serves. Currently, Union delivers natural gas services to over 1.3 million homes and businesses in over 400 communities in Ontario. These types of investments are an effective tool to help position Union as a "Partner of Choice" (defined in following section) within these communities, build awareness about Union with its customers and, foster relationships with key stakeholders such as municipal, provincial and Aboriginal leaders across its franchise.

Union is seeking approval to recover $0.374 million in investment costs in 2013. Union maintains that its community investments are highly valued and represent a legitimate, necessary cost of doing business. With respect to rate recovery, since the primary intent of these investments is to benefit the community and ultimately the ratepayer, Union believes it's appropriate that these costs be passed on to the ratepayer. The forecast expense is consistent with historical investment levels

.

Partner of Choice

A strong presence in the community helps Union promote its reputation and increase its overall brand awareness. Community investments not only raise Union's profile, they also serve to enhance its reputation as a respected and valued corporate citizen, such as its varied environmental and education investments. Union's community presence is especially important at a time when its significant infrastructure program is underway. For example, an effective community investment strategy can help mitigate the risk of opposition to specific projects (i.e. pipeline expansions). This can lead to the completion of a project in a timely and most cost effective manner which is a win/win for the Company and the ratepayer. This ongoing commitment to the community helps position Union as a "Partner of Choice".

Investments in the community provide tangible and verifiable benefits to Union's ratepayers and the communities in which they live and work. Not only do they help enhance a community's overall economic health, but a strong presence in the community can also help Union's ability to influence customer behavior. This is especially relevant in areas of safety and smart energy-use. In addition, any benefits Union realizes through these types of investments will contribute to its ability to manage the risks and costs associated with its distribution, transmission and storage business. This is aligned with Union's corporate mission of providing services in a safe, reliable and, ultimately, cost effective manner.

Investment Strategy

In a typical year, Union receives numerous community investment requests. However, Union's investment strategy targets only those agencies that provide sustainable benefits to communities across its franchise territory. Union's investments typically focus on areas pertaining to safety, workforce development and education, environmental education, conservation and research as well as targeted arts/culture giving. When assessing the various community investment requests, Union considers the following criteria:

- Relevance
- Principles and Strategic Objectives
- Reputation and Brand Recognition
- Accountability and Measurement
- Volunteerism and Employee Development

In 2011, examples of Union's community investments include funding a partnership with the Chatham-Kent Children's Safety Village. The village plays an important role in helping to reduce injuries by teaching children personal responsibility and awareness regarding safety. Through their programs, children learn to identify risks and are given the opportunity to practice behaviours in a safe environment that can reduce or eliminate those risks and prevent injury. Union also provided $10,000 to a research project, led by the University's Waterloo Institute for Sustainable Energy (WISE). This research project focuses on the idea of using advanced information technology to create a fully integrated "smart energy network", one that includes natural gas, renewables and, in the future, would incorporate new fuels such as hydrogen. All decisions at Union related to community investments are, and will continue to be, consistent with its corporate values, code of business ethics and the guiding principles listed below:

- Align with the Company's focus areas of Community Vitality (Safety, Environment, Arts & Culture, Health & Human Services), Education & Workforce Development, as well as business objectives, employee interests and community needs;
- Provide long-term benefits to the communities where Union does business;
- Build capacity, not dependency, for both Union and its beneficiaries;
- Encourage participative partnerships in which Union donates its talents and capabilities as well as monetary assistance;
- Be based on real community needs, and reflect the cultural, social and economic profile of communities where Union does business; and,
- Ensure that both the beneficiaries and Union understand the benefits that will arise both prior to the investment and during an accountability process after a specified period of time.

PREFILED EVIDENCE OF

BILL FAY, MANAGER, UNDERGROUND STORAGE

CAROL CAMERON, MANAGER, CAPACTIY MANAGEMENT & UTILIZATION

The purpose of this evidence is to update the integrity space requirement included in Union's delivery rates. This evidence will discuss:

1/ Rationale for System Integrity

2/ Historical System Integrity in Rates

3/ Proposed System Integrity Space for 2013

1/ RATIONALE FOR SYSTEM INTEGRITY

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.

2/ HISTORICAL SYSTEM INTEGRITY IN RATES

To manage Union's integrated system operations it was determined in E.B.R.O. 499 that 257,780 10^3m^3 (9.7 PJ) of storage space was required. This consisted of:

	10^3m^3	PJ
Southern storage	240,780	9.1
Northern LNG	17,000	0.6
	257,780	9.7

As part of the unbundling of Union’s infranchise services (RP-1999-0017) it was necessary to define the various operational components and the associated drivers to allocate system integrity costs to rate classes. As a result, the operational risks associated with being a provider of last resort were identified and the “system integrity space” necessary to support the potential deliverability shortfalls was estimated based on operational experience. The total system integrity space was estimated at 9.7 PJ. Since RP-1999-0017, the total system integrity space has remained the same.

3/ Proposed System Integrity Space and Allocation for 2013

Union’s proposed allocation of the system integrity space among the operational components relative to the allocation in EB-2005-0520 is shown below in Table 1.

Table 1
Comparison of Allocation of System Integrity Space

Line No.	System Integrity Operational Components	Current (EB-2005-0520) (PJ)	Proposed (EB-2011-0210) (PJ)
1	Forecasted Weather Variances	3.5	2.6
2	UFG Forecast Variances	1.8	2.2
3	System Line Pack	1.7	1.1
4	Storage Pool Hysteresis	0.5	2.0
5	OBA/LBA Imbalances	0.3	0.9
6	Supply Backstopping	1.8	0.7
7	Total	9.7	9.5

The increase in the hysteresis component has resulted in a reallocation of the system integrity space to the other components (ie. weather, UFG, line pack, OBA/LBA and supply backstopping) based on the diversity of the expected outcomes. The increase in pool hysteresis has been driven by higher than expected well interference in Union's storage pools. Well interference results in lower effective pool pressures which in turn lowers the overall well flow performance. The magnitude of well interference effects depends largely on the individual pool characteristics, system demands and the length of sustained withdrawals or injections.

The individual components making up the operational requirements for system integrity space are discussed below:

1. Forecasted Weather Variations

Daily gas nominations are based upon a weather forecast prepared prior to the beginning of the gas day. Weather that is colder than forecasted could therefore require higher system deliverability than planned.

2. UFG Forecasted Variances

Variances between actual and forecasted unaccounted-for-gas (“UFG”) volumes can result in a lower than expected storage inventory balance. The lower than expected inventory as a result of higher than forecasted UFG could result in a shortfall in storage deliverability.

3. System Line Pack

Swings in system line pack due to unexpected upsets and unplanned system demands may result in the necessity to withdraw from storage to replenish line pack on Union’s Dawn - Parkway, Panhandle, and Sarnia systems.

4. Storage Pool Hysteresis

Storage pool deliverability performance can be influenced by localized pressure drawdown across the reservoir as a result of withdrawal and injection operations. The reduction in the effective reservoir pressure resulting from this drawdown is referred to as hysteresis. The lower effective reservoir pressure results in lower deliverability performance from storage.

5. OBA/LBA Imbalances

Operational balancing agreement ("OBA") and load balancing agreement ("LBA") imbalances occur daily at various delivery and receipt points on Union's system. To the extent that the OBA/LBA imbalances draft Union's system on any given day an equivalent volume from Union storage is required to balance supplies and demands on Union's system.

6. Supply Backstopping

Supply backstopping is required to cover supply failure in the event of an unscheduled upstream compressor upset or pipeline interruption. Although these events are rare, the consequences can be significant.

Union's system integrity space, as described above, is composed of both 3.5 PJ of empty and 6.0 PJ of filled storage. Union requires both empty and filled space for the following reasons:

1) 3.5 PJ of empty space on November 1st to manage late season injection requirements. As storage pools are filled, pools are shut-in for stabilization. This stabilization period is critical to the ongoing inventory monitoring, operation and integrity of the storage reservoirs. As pools are shut-in during the later part of the injection season the number of pools available for injections is reduced. Managing October and November gas receipts becomes increasingly difficult as temperatures can vary considerably at this time of year. Some components that are managed with the empty space include:

    i. forecasted weather variances

ii. unaccounted-for-gas forecast variances
iii. storage pool hysteresis
iv. OBA/LBA imbalances

2) 6.0 PJ (including 0.6 PJ Hagar LNG) of filled space to meet winter operational requirements resulting from system upsets, imbalances and forecast variances. These include:

i. forecasted weather variances
ii. unaccounted-for-gas forecast variances
iii. line pack variances
iv. storage pool hysteresis
v. OBA/LBA imbalances
vi. supply backstopping

PREFILED EVIDENCE OF

BRYAN GOULDEN, MANAGER, MARKET DEVELOPMENT

The purpose of this evidence is to outline Union's proposed level of funding for the Energy Technology and Innovation Canada ("ETIC") program. This evidence is organized under the following headings:

1/ ETIC Program
2/ Utility Spending on Innovation and Technology
3/ Union's ETIC Commitment

1/ ETIC PROGRAM

Average investment in technology and innovation across North American gas utilities lags investment made by other major worldwide natural gas and electric utilities. To help address the lack of investment in technology and innovation, the CGA Board of Directors approved the establishment of an energy technology innovation fund in September 2010, commencing in 2011, consistent with the CGA's vision that by 2015:

> *"The natural gas delivery industry is recognized as the leader in delivering smart energy solutions to consumers in support of sustainable communities:*
>
> i. *Seen by governments as the best industry to deliver low carbon energy to the consumer.*
>
> ii. *Seen by the consumer as best positioned to help them optimize their consumption.*

With gas as a foundation fuel, the industry provides Canada's communities, business and industry with clean, safe and reliable, energy while operating in a policy, regulatory, technical and partnership landscape that supports superior returns on investment."

To help Canada achieve a low carbon energy future and ensure the continued relevance of natural gas as a foundational fuel, Canadian natural gas utilities need to invest appropriately in technology commercialization and innovation in end use oriented markets.

Initially the overall focus of ETIC is to facilitate and drive natural gas technology innovation that ensures natural gas remains a preferred foundational fuel. This will be achieved through identifying technology gaps, accessing and sharing information among the member companies and 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. ETIC is intended to be a research provider for its members, either directly through management of specific research projects or indirectly through investments in project funding on a collaborative basis with other interested stakeholders.

Natural gas market share has been stable or declining in all market sectors since 1990 with the exception of power generation that has shown growth prospects. This trend is expected to continue, as a result of tighter building and equipment regulation, a significant focus on energy conservation/ DSM and greenhouse gas mitigation initiatives involving natural gas. In this time of market transition, the industry needs to continue to ensure that natural gas technology options meet the needs of customers and other energy industry stakeholders. Strategic investment in technology is a critical tool in achieving this objective.

Union believes it is critical to increase its participation in industry wide evaluation and implementation of new technologies. Although key fundamental gas technologies exist today, the most significant challenges continue to be in the adaptation and deployment of natural gas based innovative technology solutions. For example, natural gas residential space heating technology has been developed to the point that the high efficiency furnace is the current de facto appliance of choice in most high end residential detached housing developments (where gas is available). High efficiency natural gas furnaces have a combustion efficiency in excess of 90% and have a significant operating cost and current life cycle cost advantage relative to other energy forms. However, the next generation of natural gas residential space heating appliances needs to be developed to compete with other technology choices. This development is unlikely to occur without the innovation investment and active investment of the gas industry.

As a gas distribution company, Union understands the customer's expectations with respect to safety, reliability and affordability and is well positioned to identify the optimum technology solutions that will meet future expectations of high energy efficiency while addressing the need to reduce carbon emissions. Success depends on gaining regulatory support for investment in technology and innovation areas that support the transition to a low carbon energy system. Projects funded under ETIC will be those that provide an opportunity to help Union better understand the realities of emerging technologies or that have potential impact on Union's business model. All project investments will be scope and time bound and leveraged to ensure the participation of other stakeholders including manufacturers, suppliers, international gas utilities, government and Non -Governmental Organizations. Union will work to ensure that the investments made will provide value to natural gas rate payers through prudent, leveraged expenditures on technology innovation.

2/ UTILITY SPENDING ON INNOVATION AND TECHNOLOGY

As indicated above, North American gas utilities lag other major worldwide natural gas utilities in investments in technology and innovation. The 2011 "EU Industrial R&D Investment Scoreboard" (the "Scoreboard") collects information on the top 1,000 EU companies and 1,000 non-EU companies investing the largest sums in R&D in the last reporting year. The Scoreboard includes data on R&D investment along with other economic and financial data from the last four financial years.

As indicated in Table 1, the level of R&D investment for the six "primarily natural gas" utilities included in this survey is 0.29% of total sales revenue.

Table 1

World Natural Gas Utility Research & Development Investment
(per 2011 EU RD Scorecard)

No	Company	Rank	Country	2010 R&D Investment (€m)	Net Sales (€m)	Employees	R&D/Net Sales Ratio	Operating Profit (% of Net Sales)	Market Capitalization (€m)
1	RWE	82	Germany	261.00	50,722.00	71,001	0.51%	13.36%	20,795.7
2	GDF SUEZ	90	France	222.00	84,478.00	236,116	0.26%	10.56%	51,928.8
3	E.ON	213	Germany	88.00	94,426.00	87,770	0.09%	7.72%	39,013.7
4	National Grid	519	UK	18.67	16,739.72	27,672	0.11%	26.72%	25,693.0
5	Osaka Gas	454	Japan	98.07	10,079.18	19,268	0.97%	-7.09%	6,052.0
6	Tokyo Gas	507	Japan	84.85	13,011.96	15,539	0.65%	6.04%	9,247.6
	Average			772.60	269,456.85		0.29%		

Source: http://iri.jrc.es/research/scoreboard_2011.htm

As indicated in Table 2 the level of R&D investment for the 17 electric power utilities included in this survey is 0.67% of total sales revenue. Union notes that no North American gas utilities were identified as being in the top 1000 R&D funders worldwide outside the EU. The only North American electric utility to be identified on this listing is Hydro Quebec with 2010 R&D expenditures equal to 0.81% of its total sales revenue.

Table 2
World Natural Gas Utility Research & Development Investment
(per 2011 EU RD Scorecard)

				2010					
No	Company	Rank	Country	R&D Investment (€m)	Net Sales (€m)	Employees	R&D/Net Sales Ratio	Operating Profit (% of Net Sales)	Market Capitalization (€m)
1	Korea Electric Power	141	South Korea	440.5	25,896.3	37,332	1.70%	4.55%	11,674.7
2	Tokyo Electric Power	176	Japan	345.0	46,104.8	52,452	0.75%	6.57%	6,978.6
3	Kansai Electric Power	291	Japan	180.3	23,957.4	32,083	0.75%	9.01%	11,496.6
4	Chubu Electric Power	374	Japan	127.8	20,574.7	29,116	0.62%	9.55%	9,502.6
5	Kyushu Electric Power	463	Japan	96.0	13,280.5		0.72%	7.12%	5,482.5
6	Tohoku Electric Power	516	Japan	82.3	15,288.3	22,479	0.54%	5.59%	4,809.4
7	Hydro-Quebec	558	Canada	75.0	9,256.1	19,521	0.81%	48.22%	
8	Chugoku Electric Power	657	Japan	59.3	9,544.4	14,146	0.62%	7.26%	4,400.9
9	Taiwan Power	695	Taiwan	55.7	13,069.0		0.43%	(1.43%)	
10	Electric Power Development	703	Japan	54.7	5,372.0	6,701	1.02%	11.15%	3,280.6
11	Shikoku Electric Power	783	Japan	47.2	5,012.7		0.94%	8.43%	3,669.7
1	AREVA	52	France	520.0	11,112.0	47,851	4.68%	(2.87%)	10,132.5
2	Electricite de France	55	France	486.0	72,481.0	158,764	0.67%	5.96%	49,509.1
3	Vattenfall	99	Sweden	207.6	23,681.3	38,459	0.88%	13.91%	
4	Iberdrola	158	Spain	130.2	30,431.0	31,344	0.43%	15.80%	33,451.4
5	Enel	210	Italy	89.0	71,943.0	79,913	0.12%	15.45%	38,637.2
6	Scottish and Southern Energy	321	UK	45.1	33,068.8	20,266	0.14%	8.23%	14,675.8
7	Terna	338	Italy	42.4	2,036.4	3,486	2.08%	46.77%	6,447.1
8	Energias de Portugal	363	Portugal	36.5	14,170.7	12,096	0.26%	14.75%	8,433.7
9	EnBW Energie Baden-Wurtter	379	Germany	34.3	17,509.0	20,450	0.20%	9.45%	10,129.5
10	Fortum	405	Finland	30.0	6,296.0	11,156	0.48%	28.02%	16,878.5
11	Cez	419	Czech Repub	28.3	7,925.8	32,937	0.36%	32.89%	20,079.3
12	Teollisuuden Voima	486	Finland	21.6	362.6	842	5.96%	43.48%	
13	International Power	511	UK	19.8	3,902.8	3,520	0.51%	19.62%	18,739.8
14	Urenco	548	UK	16.7	1,267.2	3,264	1.32%	46.62%	
15	Elia System Operator	705	Belgium	10.9	939.5	1,163	1.16%	29.12%	1,803.9
16	Red Electrica De Espana	952	Spain	5.0	1,397.3	1,695	0.36%	46.47%	5,239.5
17	Osterreichische Elektrizitatswir	978	Austria	4.8	3,307.9	3,015	0.15%	25.67%	4,904.1
	Average			3,292.0	489,188.4		0.67%		

Source: http://iri.jrc.es/research/scoreboard_2011.htm

3/ **UNION'S ETIC COMMITMENT**

Union's proposed 2013 O&M budget includes $5.0 million related to the ETIC program. This amount is consistent with the average level of R&D investment for the six "primarily natural gas" utilities included in the 2011 EU scorecard.[1]

[1] $1,830 million x 0.29% = $5.307 million.

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

ETIC spending will not exceed the amount included in approved rates. In any year when ETIC expenditures are less than the amount included in approved rates, ratepayers will credited the difference. For example, in the event that Union spends $4.25 million of its budgeted $5.0 million ETIC commitment, the remaining $0.75 million would be returned to the credit of the ratepayer in the following year. Union's request for approval of the ETIC Deferral Account appears at Exhibit H1, Tab 5.

UNION GAS LIMITED
Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Board Approved 2007	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	
		(a)	(b)	(c)	(d)	(e)	
1	Cost of gas	1,135,825	795,549	755,941	721,228	697,838	/u
2	Operating and maintenance	326,222	351,634	371,731	383,774	393,228	/u
3	Depreciation	173,780	190,176	195,477	204,145	196,467	/u
4	Other financing	315	621	343	362	1,179	/u
5	Property and capital taxes	67,709	65,131	60,700	62,916	64,022	/u
6	Other expense	-	500	(709)	-	-	
7	Income taxes	14,589	30,214	33,119	18,560	6,574	/u
8	Cost of service excluding return	1,718,440	1,433,825	1,416,602	1,390,985	1,359,308	/u

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 (5)	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	/u
2	Benefits	55,621.0	56,364.5	51,366.1	52,919.0	70,861.2	81,178.8	82,161.4	81,082.7 (3)	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
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	/u
15	Donations	404.0	377.2	451.0	500.8	749.1	631.8	774.6	787.6	/u
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	/u
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	/u
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)	/u
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	/u
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	/u
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)	/u
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	/u
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	/u
24	Other	100.0	100.8	236.5	738.6	248.2	209.8	140.4	141.0	/u
25	Total	391,907.0	381,955.3	396,380.9	395,078.2	423,677.4	452,141.9	466,787.0	479,881.2	/u
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)	(51,376.0)	/u
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)	/u
28	Total Capitalization	(58,878.0)	(54,525.9)	(61,265.6)	(59,594.2)	(60,267.9)	(67,369.0)	(69,808.1)	(73,027.6)	/u
29	Total	333,029.0	327,429.4	335,115.3	335,484.0	363,409.5	384,772.9	396,978.9	406,853.6	/u
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)	(13,625.3)	/u
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	393,228.3	/u
34	Excess Utility Cross-Charge (4)	(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	390,967.3	/u

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 defined benefit pension costs are US GAAP CDN Reporting (see Exhibit D1 Tab 3 for further details). /u
(4) 2013 Utility Cross-Charge is an estimate and will be updated as part of the cost study. /u
(5) 2011 Actuals do not include $6M reduction related to St. Clair. /u

Filed: 2011-11-10
EB-2011-0210
Exhibit D2

2011 Depreciation Rate Study

CONTENTS

DISTRIBUTION

47800S – METERS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Union Gas Limited (Union). The report contains recommended 2011 depreciation rates and parameters for: a) intangible assets; b) local and underground storage facilities; and c) gas transmission, distribution and general plant categories. Work on the study commenced in March 2011 and progressed through early July, at which time the project was completed.

Foster Associates, Inc. is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

This is the eighth major depreciation study undertaken by Union in the last 40 years. Current depreciation rates were developed by Foster Associates in a 2003 comprehensive study in which revised parameters were estimated for all plant accounts. Rates currently used by Union were adopted September 19, 2003 pursuant to an Alternative Dispute Resolution Agreement approved by the Ontario Energy Board (OEB) under Docket No. RP–2003–0063. The settlement agreement accepted all depreciation rates developed in the 2003 study.

On January 1, 1998, Union Gas formalized a legal merger with Centra Gas Ontario. The depreciation rates adopted by Union in RP–2003–0063 retained the pre–merger corporate identity for plant classified in the Distribution function. This treatment was adopted to preserve a jurisdictional separation of distribution plant for ratemaking purposes. While it is the intention of Union to eventually eliminate the pre–merger corporate identity of former Centra assets, the current study retains the distinction between Northern and Eastern Operations (previously Centra) and the Southern Operations of Union for plant classified in the Distribution function.

The current study also preserves the elimination of Accounts 49601 and 49602 (Contributions in Aid of Construction) proposed in the 2003 study and approved in RP–2003–0063. Depreciation rates developed prior to the 2003 study included rates for the CIAC accounts derived from a composite weighted average of the accrual rates for the major plant accounts in which investments were funded by contributions. The current treatment of CIAC is to credit the associated plant accounts as previously permitted by the OEB Uniform System of Accounts for Gas Utilities.[1] Depreciation reserves for the CIAC accounts were distributed and combined with the associated plant reserves in the 2003 study.

The principal findings and recommendations of the 2011 study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain a weighted-average net salvage rate for each plant account. Statement F provides the computation of future net salvage rates for the Local Storage function. Statement G provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Communication with Union plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

[1] Contributions or grants in cash, services or property from governments or government agencies, corporations, individuals, and others for contributions in aid of construction shall be applied as a reduction of the detail plant accounts to which they refer, if not recorded separately in Account No. 499, "Contributions and Grants". (USOA, Appendix A, Section 1, Part B)

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, Union is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

Amortization accounting is also recommended in the current study for Account 47400 (Regulators). The numerous property units classified in this account are relatively low–cost items with no record–keeping system in place to track the physical disposition of the assets. Moreover, house regulators for new installations are now typically pre–assembled as a component of a meter manifold and classified as minor items of property in Account 47401 (Regulator and Meter Installations). Reserve imbalances resulting from the proposed 20–year amortization period for Account 47400 were distributed to the remaining depreciable accounts within the Distribution plant function for the Northern and Eastern Operations and the Southern Operations, respectively.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage group procedure, which distinguishes average service lives among vintages, and the remaining–life technique which provides cost apportionment over the estimated weighted average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories. Accordingly, the depreciation system currently prescribed for Union was used in the current study to develop accrual rates proposed for calendar year 2011.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

Function	Accrual Rate Current	Accrual Rate Proposed	Accrual Rate Diff.	2011 Annualized Accrual Current	2011 Annualized Accrual Proposed	2011 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	5.05%	5.45%	0.40%	$ 61,555	$ 66,431	$ 4,876
Local Storage	3.35%	3.16%	-0.19%	570,449	538,330	(32,119)
U/G Stirage	3.04%	2.63%	-0.41%	13,397,696	11,563,828	(1,833,868)
Transmission	2.70%	2.27%	-0.43%	42,624,294	35,809,174	(6,815,120)
Distribution	2.99%	2.78%	-0.21%	104,669,492	97,199,048	(7,470,444)
General Plant	10.99%	11.70%	0.71%	27,332,018	29,068,934	1,736,916
Total	3.26%	3.01%	-0.25%	$188,655,504	$174,245,745	$(14,409,759)

Table 1. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.01 percent. Depreciation expense is currently accrued at an equivalent composite rate of 3.26 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.25 percentage points.

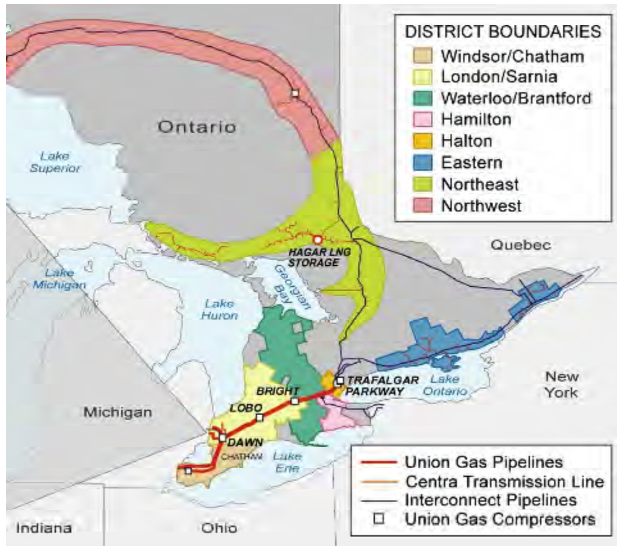
A continued application of current rates would provide annualized depreciation expense of $188,655,504 compared with an annualized expense of $174,245,745 using the rates developed in this study. The proposed expense reduction is $14,409,759. The change in annualized accruals includes a reduction of $2,837,776 attributable to an amortization of a $74,728,569 reserve imbalance. A proportionate amount of the estimated reserve imbalance will be amortized over the weighted average remaining life of each rate category. The remaining portion of the change in accruals is attributable to recommended adjustments to various service life and net salvage parameters.

Of the 41 property accounts included in the 2011 study, Foster Associates is recommending rate reductions for 29 accounts and rate increases for 12 accounts.

COMPANY PROFILE

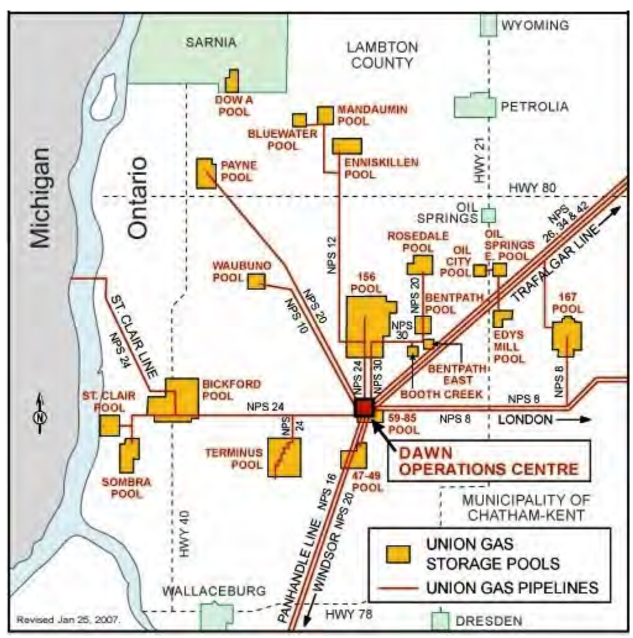
GENERAL

Union Gas Limited, a Spectra Energy Company, is a major Canadian natural gas utility that provides energy delivery and related services to 1.3 million residential, commercial and industrial customers in over 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southwestern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall.



The Company also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec and the United States. Union Gas has assets of approximately $5.6 billion including 25,574 miles of distribution mains, 15,024 miles of distribution services, and 2,946 miles of transmission pipelines. The Company employs about 2,200 people.

The Dawn Hub is the largest natural gas storage facility in Canada. With six pipeline interconnects—three of which are TransCanada's—Union Gas has easy access to 15 pipeline and distribution companies. The Dawn Hub is an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S. Dawn has a working capacity of 155 Bcf and can deliver 2 Bcf a day to customers.



STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Union. The proposed rates are subject to approval by the Ontario Energy Board.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi-actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records.

Prior to 1994, Union did not have a plant accounting system within which aged plant records could be maintained. In October, 1994 the Company implemented an in–house, designed and developed Continuing Property Record (CPR) system with vintage year identification of plant in service at March 31, 1994. Property tax records were used to construct the age distribution of pre–1982 vintages and the aging of post–1982 vintages was obtained from a detailed analysis of subsidiary plant records. The Company adopted calendar year accounting for financial reporting purposes commencing with calendar year 1995, which was reported as a nine–month accounting period.

On April 1, 1997 the in–house system was converted to a commercial product developed by SAP. The new system was populated with vintage year identification of plant in service at December 31, 1996. Plant accounting records for the Northern and Eastern Operations (formerly Centra) were also uploaded to the new Union system on April 1, 1997.

With the exception of Accounts 45200 (Structures and Improvements), 46200 (Structures and Improvements), 47200 (Structures and Improvements) and 48200 (Structures and Improvements), Union can now provide plant accounting transactions with vintage year identification for post–1997 activity for all remaining plant categories,. The vintage year assigned to plant activity associated with structures and improvements is the year the plant was originally constructed. While this practice will not misstate the aggregate investment in a plant category, the reported age distribution of surviving plant is not representative of the actual age of the investments. An aged data base was assembled by Foster Associates for all plant categories over the period 1997 through 2002 in conducting the 2003 study.

Service life statistics estimated in the current study were derived from plant accounting transactions recorded over the period 1997 through 2010. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2003 study was updated for the current study by appending plant and net salvage transactions for activity years 2003–2010 and age distributions of surviving plant at December 31, 2010. The accuracy and completeness of the assembled database was verified for activity years 2003 through 2010 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2003 were verified in the 2003 study. Age distributions of surviving plant at December 31, 2010 were reconciled to the CPR system.

Reserve transactions recorded over the period 1997–2010 were used in the 2011 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two-step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and probability distribution descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi-actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi-actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2011 depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study to analyze post–1997 plant accounting activity. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio (or set of ratios) is referred to as a retirement ratio. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. In addition to performing the life analysis as discussed above, the programs offer tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, mains and services), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the present system. A proper depreciation rate can be developed for an integrated system using a life–span method.

The life–span method requires the selection of a coterminous retirement date for all plant additions to a specific facility. A composite depreciation rate is calculated for the facility using the technique of harmonic weighting of the expected life span of each vintage addition. The resulting accrual rate must be adjusted for interim retirements to the extent that such retirements can be reasonably expected. Absent this adjustment, the depreciation accumulated over the life span of the facility will be deficient by an amount equal to a portion of the interim retirements. Properly implemented, the life–span method does not include plant additions or replacements of interim retirements until such activity is reported. All accounts in the Local Storage function, Account 45200 (Structures and Improvements) in the Underground Storage function and Account 48200 (Structures and Improvements) in the General plant function were treated as life–span categories in this study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2011 study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of the estimated average net salvage rate for each rate category is shown in Statement E.

A 1994 dismantlement study conducted by Stone & Webster Canada Limited for the Hagar LNG plant (previously owned by Centra) was used in the 2003 depreciation study to derive a reasoned estimate of a net salvage rate for the Local Storage function. Noting that the estimated year of final retirement has been extended from 2017 to 2025 and a dismantlement study more recent than 1994 has not been conducted, terminal net salvage was removed from the estimate of future net salvage rates in the current study. It remains the opinion of Foster Associates, however, that terminal net salvage should be included in the formulation of deprecation rates when an updated dismantlement study becomes available. The computations supporting the recommended weighted–average interim and final net salvage rates for the Local Storage function are shown in Statement F.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of plant units still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of the depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for Union. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current study) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves (net of amortizable accounts) to the function total calculated reserve.[2] The sum of the redistributed reserves within a function is, therefore, equal to the function (or operating division) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Statement C provides a comparison of the computed, recorded and redistributed reserves for Union at December 31, 2010. The total recorded reserve was $2,406,759,893 or 41.6 percent of the total utility plant investment. The corresponding computed reserve is $2,332,031,324 or 40.3 percent of the total utility plant investment. A proportionate amount of the measured reserve imbalance of $74,728,569 will be amortized over the composite weighted-average remaining life of each rate category.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is most often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time-based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a

[2] The distinction between North and South operations was retained in rebalancing depreciation reserves. Accordingly, recorded reserves were redistributed within each operating division.

time–based allocation method, however, does not change the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 study were developed using the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for Union, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate these plant categories.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to average plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense by a half–period accrual on vintages that will be retired during the study year. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to average plant balances after retiring vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage parameters recommended for Union. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the straight–line method, vintage group procedure, remaining-life technique.
- Statement B provides a comparison of the current and proposed annualized 2011 depreciation accruals derived from the depreciation rates developed in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for Local Storage plant.
- Statement G provides a comparative summary of current and proposed parameters and statistics.

Current depreciation accruals shown on Statement B are the product of plant investments at December 31, 2010 (Column B) and current depreciation rates shown on Statement A. Similarly, proposed depreciation accruals shown on Statement B are the product of the year–end 2010 plant investments and proposed depreciation rates shown on Statement A. The proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

UNION GAS LIMITED
Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
40100 Franchises and Consents	5.05%		5.05%	5.45%		5.45%
Total Intangible Plant	5.05%		5.05%	5.05%	0.40%	5.45%
LOCAL STORAGE PLANT						
44200 Structures and Improvements	2.35%	0.95%	3.30%	2.85%		2.85%
44301 Gas Holders - Storage Tank	2.31%	0.37%	2.68%	2.53%	0.01%	2.54%
44302 Gas Holders - Equipment	2.49%	1.19%	3.68%	3.52%	0.02%	3.54%
Total Local Storage Plant	2.42%	0.93%	3.35%	3.34%	-0.18%	3.16%
UNDERGROUND STORAGE PLANT						
45100 Land Rights	2.23%		2.23%	2.10%		2.10%
45200 Structures and Improvements	2.23%	0.12%	2.35%	2.26%	0.24%	2.50%
45300 Wells and Lines	2.21%	0.44%	2.65%	2.05%	0.43%	2.48%
45600 Compressor Equipment	2.91%	0.29%	3.20%	2.56%	0.12%	2.68%
45700 Measuring and Regulating Equipment	3.95%	0.35%	4.30%	2.86%	0.25%	3.11%
Total Underground Storage Plant	2.76%	0.28%	3.04%	2.81%	-0.18%	2.63%
TRANSMISSION PLANT						
46100 Land Rights	2.01%	-0.02%	1.99%	1.76%		1.76%
46200 Structures and Improvements	2.54%	0.12%	2.66%	1.84%	0.19%	2.03%
46501 Mains - Metallic	2.02%	0.35%	2.37%	1.72%	0.26%	1.98%
46600 Compressor Equipment	3.36%	0.16%	3.52%	3.12%	0.11%	3.23%
46700 Measuring and Regulating Equipment	3.36%	0.26%	3.62%	2.36%	0.24%	2.60%
Total Transmission Plant	2.41%	0.29%	2.70%	2.44%	-0.17%	2.27%
DISTRIBUTION PLANT						
Northern and Eastern Operations						
47100 Land Rights	1.68%		1.68%	1.71%		1.71%
47200 Structures and Improvements	2.86%	0.27%	3.13%	2.46%	-0.05%	2.41%
47301 Services - Metallic	2.25%	1.33%	3.58%	1.99%	1.23%	3.22%
47302 Services - Plastic	1.83%	1.36%	3.19%	1.85%	0.75%	2.60%
47400 Regulators	3.35%	-0.01%	3.34%	← 20 Year Amortization →		3.72%
47401 Regulator and Meter Installations	3.34%	0.16%	3.50%	2.92%		2.92%
47501 Mains - Metallic	2.02%	0.50%	2.52%	1.89%	1.13%	3.02%
47502 Mains - Plastic	1.68%	0.67%	2.35%	1.70%	0.68%	2.38%
47700 Measuring and Regulating Equipment	3.59%	1.03%	4.62%	2.51%	1.26%	3.77%
47800 Meters	3.74%	-0.07%	3.67%	4.05%	-0.02%	4.03%
Total Northern and Eastern Operations	2.22%	0.81%	3.03%	2.20%	0.69%	2.89%
Southern Operations						
47100 Land Rights	1.67%		1.67%	1.65%		1.65%
47200 Structures and Improvements	2.85%	0.06%	2.91%	2.31%	-0.09%	2.22%
47301 Services - Metallic	2.28%	1.42%	3.70%	1.79%	1.02%	2.81%
47302 Services - Plastic	1.83%	1.35%	3.18%	1.80%	0.71%	2.51%
47400 Regulators	3.33%	-0.04%	3.29%	← 20 Year Amortization →		4.08%
47401 Regulator and Meter Installations	3.35%	0.15%	3.50%	2.80%		2.80%
47501 Mains - Metallic	2.03%	0.51%	2.54%	1.76%	1.07%	2.83%
47502 Mains - Plastic	1.68%	0.67%	2.35%	1.65%	0.66%	2.31%
47700 Measuring and Regulating Equipment	3.58%	1.06%	4.64%	2.42%	1.24%	3.66%
47800 Meters	3.71%	-0.01%	3.70%	3.85%	-0.03%	3.82%
Total Southern Operations	2.18%	0.78%	2.96%	2.26%	0.45%	2.71%
Total Distribution Plant	2.20%	0.79%	2.99%	2.24%	0.54%	2.78%

UNION GAS LIMITED

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Current (at 12/31/2010) Net Salvage	Current (at 12/31/2010) Total	Proposed (at 12/31/2010) Investment	Proposed (at 12/31/2010) Net Salvage	Proposed (at 12/31/2010) Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
48200 Structures and Improvements	2.62%	-0.50%	2.12%	2.38%	-0.46%	1.92%
48400 Transportation Equipment	14.21%	-4.14%	10.07%	15.76%	-2.49%	13.27%
48500 Heavy Work Equipment	6.64%	-2.09%	4.55%	7.17%	-0.25%	6.92%
Total Depreciable	8.28%	-2.33%	5.95%	7.00%	0.64%	7.64%
Amortizable						
48310 Office Furniture and Equipment	← 15 Year Amortization →		6.22%	← 15 Year Amortization →		6.22%
48320 Office Equipment - Computers	← 4 Year Amortization →		20.37%	← 4 Year Amortization →		20.37%
48601 Tools and Other Equipment	← 15 Year Amortization →		6.41%	← 15 Year Amortization →		6.41%
48801 Communication Equipment	← 15 Year Amortization →		5.67%	← 15 Year Amortization →		5.67%
Total Amortizable	14.57%		14.57%	14.58%	-0.01%	14.57%
Total General Plant	11.96%	-0.97%	10.99%	11.43%	0.27%	11.70%
TOTALGAS UTILITY	2.72%	0.54%	3.26%	2.74%	0.27%	3.01%

UNION GAS LIMITED

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual Investment	Current 2011 Annualized Accrual Net Salvage	Current 2011 Annualized Accrual Total	Proposed 2011 Annualized Accrual Investment	Proposed 2011 Annualized Accrual Net Salvage	Proposed 2011 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
INTANGIBLE PLANT								
40100 Franchises and Consents	$1,218,909	$61,555		$61,555	$ 66,431	$ -	$ 66,431	$ 4,876
Total Intangible Plant	$1,218,909	$61,555		$61,555	$ 66,431	$ -	$ 66,431	$ 4,876
LOCAL STORAGE PLANT								
44200 Structures and Improvements	$ 2,674,066	$ 62,841	$ 25,404	$ 88,245	$ 76,211	$ -	$ 76,211	$ (12,034)
44301 Gas Holders - Storage Tank	4,574,078	105,661	16,924	122,585	115,724	457	116,181	(6,404)
44302 Gas Holders - Equipment	9,772,265	243,329	116,290	359,619	343,984	1,954	345,938	(13,681)
Total Local Storage Plant	$ 17,020,409	$ 411,831	$ 158,618	$ 570,449	$ 535,919	$ 2,411	$ 538,330	$ (32,119)
UNDERGROUND STORAGE PLANT								
45100 Land Rights	$ 32,062,296	$ 714,989	$ -	$ 714,989	$ 673,308	$ -	$ 673,308	$ (41,681)
45200 Structures and Improvements	55,119,051	1,229,155	66,143	1,295,298	1,245,691	132,286	1,377,977	82,679
45300 Wells and Lines	87,601,565	1,935,995	385,447	2,321,442	1,795,832	376,687	2,172,519	(148,923)
45600 Compressor Equipment	214,182,254	6,232,704	621,129	6,853,833	5,483,066	257,019	5,740,085	(1,113,748)
45700 Measuring and Regulating Equipment	51,444,990	2,032,077	180,057	2,212,134	1,471,327	128,612	1,599,939	(612,195)
Total Underground Storage Plant	$ 440,410,156	$ 12,144,920	$ 1,252,776	$ 13,397,696	$ 10,669,224	$ 894,604	$ 11,563,828	$ (1,833,868)
TRANSMISSION PLANT								
46100 Land Rights	$ 37,709,004	$ 757,951	$ (7,542)	$ 750,409	$ 663,678	$ -	$ 663,678	$ (86,731)
46200 Structures and Improvements	53,543,879	1,360,015	64,253	1,424,268	985,207	101,733	1,086,940	(337,328)
46501 Mains - Metallic	1,041,972,208	21,047,839	3,646,903	24,694,742	17,921,922	2,709,128	20,631,050	(4,063,692)
46600 Compressor Equipment	300,909,097	10,110,546	481,455	10,592,001	9,388,364	331,000	9,719,364	(872,637)
46700 Measuring and Regulating Equipment	142,620,842	4,792,060	370,814	5,162,874	3,365,852	342,290	3,708,142	(1,454,732)
Total Transmission Plant	$ 1,576,755,030	$ 38,068,411	$ 4,555,883	$ 42,624,294	$ 32,325,023	$ 3,484,151	$ 35,809,174	$ (6,815,120)
DISTRIBUTION PLANT								
Northern and Eastern Operations								
47100 Land Rights	$ 9,011,143	$ 151,387	$ -	$ 151,387	$ 154,091	$ -	$ 154,091	$ 2,704
47200 Structures and Improvements	61,811,428	1,767,807	166,891	1,934,698	1,520,561	(30,906)	1,489,655	(445,043)
47301 Services - Metallic	92,761,004	2,087,123	1,233,721	3,320,844	1,845,944	1,140,960	2,986,904	(333,940)
47302 Services - Plastic	354,120,371	6,480,403	4,816,037	11,296,440	6,551,227	2,655,903	9,207,130	(2,089,310)
47400 Regulators	27,055,553	906,361	(2,706)	903,655	1,025,405	(18,283)	1,007,122	103,467
47401 Regulator and Meter Installations	29,092,211	971,680	46,548	1,018,228	849,493		849,493	(168,735)
47501 Mains - Metallic	351,222,754	7,094,700	1,756,114	8,850,814	6,638,110	3,968,817	10,606,927	1,756,113
47502 Mains - Plastic	201,072,312	3,378,015	1,347,184	4,725,199	3,418,229	1,367,292	4,785,521	60,322
47700 Measuring and Regulating Equipment	103,778,777	3,725,658	1,068,921	4,794,579	2,604,847	1,307,613	3,912,460	(882,119)
47800 Meters	52,403,372	1,959,886	(36,682)	1,923,204	2,122,337	(10,481)	2,111,856	188,652
Total Northern and Eastern Operations	$ 1,282,328,925	$ 28,523,020	$10,396,028	$ 38,919,048	$ 26,730,244	$ 10,380,915	$ 37,111,159	$ (1,807,889)

UNION GAS LIMITED

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Southern Operations								
47100 Land Rights	$ 5,494,304	$ 91,755	$ -	$ 91,755	$ 90,656	$ -	$ 90,656	$ (1,099)
47200 Structures and Improvements	101,589,573	2,895,303	60,954	2,956,257	2,346,719	(91,431)	2,255,288	(700,969)
47301 Services - Metallic	109,632,954	2,499,631	1,556,788	4,056,419	1,962,430	1,118,256	3,080,686	(975,733)
47302 Services - Plastic	741,618,024	13,571,610	10,011,843	23,583,453	13,349,124	5,265,488	18,614,612	(4,968,841)
47400 Regulators	70,083,173	2,333,770	(28,033)	2,305,737	2,929,477	(66,752)	2,862,725	556,988
47401 Regulator and Meter Installations	67,553,639	2,263,047	101,330	2,364,377	1,891,502		1,891,502	(472,875)
47501 Mains - Metallic	399,123,055	8,102,198	2,035,528	10,137,726	7,024,566	4,270,617	11,295,183	1,157,457
47502 Mains - Plastic	502,504,563	8,442,077	3,366,781	11,808,858	8,291,325	3,316,530	11,607,855	(201,003)
47700 Measuring and Regulating Equipment	29,226,321	1,046,302	309,799	1,356,101	707,277	362,406	1,069,683	(286,418)
47800 Meters	191,615,166	7,108,923	(19,162)	7,089,761	7,377,184	(57,485)	7,319,699	229,938
Total Southern Operations	$ 2,218,440,772	$ 48,354,616	$17,395,828	$ 65,750,444	$ 45,970,260	$ 14,117,629	$ 60,087,889	$ (5,662,555)
Total Distribution Plant	$ 3,500,769,697	$ 76,877,636	$27,791,856	$ 104,669,492	$ 72,700,504	$ 24,498,544	$ 97,199,048	$ (7,470,444)
GENERAL PLANT								
Depreciable								
48200 Structures and Improvements	$ 41,903,606	$ 1,097,874	$ (209,518)	$ 888,356	$ 997,306	$ (192,757)	$ 804,549	$ (83,807)
48400 Transportation Equipment	44,635,164	6,342,657	(1,847,896)	4,494,761	7,034,502	(1,111,416)	5,923,086	1,428,325
48500 Heavy Work Equipment	16,556,906	1,099,379	(346,039)	753,340	1,187,130	(41,392)	1,145,738	392,398
Total Depreciable	$ 103,095,676	$ 8,539,910	$ (2,403,453)	$ 6,136,457	$ 9,218,938	$ (1,345,565)	$ 7,873,373	$ 1,736,916
Amortizable								
48310 Office Furniture and Equipment	$ 11,113,877	$ 691,104	$ -	$ 691,104	$ 691,104	$ -	$ 691,104	$ -
48320 Office Equipment - Computers	86,088,725	17,536,122		17,536,122	17,536,122		17,536,122	
48601 Tools and Other Equipment	31,739,914	2,033,215		2,033,215	2,033,215		2,033,215	
48801 Communication Equipment	16,483,099	935,120		935,120	935,120		935,120	
Total Amortizable	$ 145,425,615	$ 21,195,561	$ -	$ 21,195,561	$ 21,195,561	$ -	$ 21,195,561	$ -
Total General Plant	$ 248,521,291	$ 29,735,471	$ (2,403,453)	$ 27,332,018	$ 30,414,499	$ (1,345,565)	$ 29,068,934	$ 1,736,916
TOTALGAS UTILITY	$ 5,784,695,492	$157,299,824	$31,355,680	$ 188,655,504	$146,711,600	$ 27,534,145	$174,245,745	$ (14,409,759)

UNION GAS LIMITED
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
40100 Franchises and Consents	$ 1,218,909	$ 361,860	29.69%	$ 567,005	46.52%	$ 361,860	29.69%
Total Intangible Plant	$ 1,218,909	$ 361,860	29.69%	$ 567,005	46.52%	$ 361,860	29.69%
LOCAL STORAGE PLANT							
44200 Structures and Improvements	$ 2,674,066	$ 2,452,635	91.72%	$ 1,429,723	53.47%	$ 1,593,357	59.59%
44301 Gas Holders - Storage Tank	4,574,078	4,574,078	100.00%	2,632,509	57.55%	2,933,801	64.14%
44302 Gas Holders - Equipment	9,772,265	7,957,005	81.42%	4,370,761	44.73%	4,870,999	49.85%
Total Local Storage Plant	$ 17,020,409	$ 14,983,718	88.03%	$ 8,432,993	49.55%	$ 9,398,157	55.22%
UNDERGROUND STORAGE PLANT							
45100 Land Rights	$ 32,062,296	$ 10,285,037	32.08%	$ 10,143,602	31.64%	$ 11,304,547	35.26%
45200 Structures and Improvements	55,119,051	23,311,865	42.29%	25,146,759	45.62%	28,024,828	50.84%
45300 Wells and Lines	87,601,565	35,711,229	40.77%	38,210,255	43.62%	42,583,453	48.61%
45600 Compressor Equipment	214,182,254	109,328,078	51.04%	95,567,655	44.62%	106,505,457	49.73%
45700 Measuring and Regulating Equipment	51,444,990	35,294,747	68.61%	27,904,535	54.24%	31,098,233	60.45%
Total Underground Storage Plant	$ 440,410,156	$ 213,930,956	48.58%	$ 196,972,806	44.72%	$ 219,516,518	49.84%
TRANSMISSION PLANT							
46100 Land Rights	$ 37,709,004	$ 8,597,685	22.80%	$ 7,685,781	20.38%	$ 8,678,444	23.01%
46200 Structures and Improvements	53,543,879	26,092,822	48.73%	22,193,777	41.45%	25,060,233	46.80%
46501 Mains - Metallic	1,041,972,208	393,578,357	37.77%	342,145,062	32.84%	386,335,086	37.08%
46600 Compressor Equipment	300,909,097	90,361,284	30.03%	96,380,379	32.03%	108,828,465	36.17%
46700 Measuring and Regulating Equipment	142,620,842	62,972,797	44.15%	46,672,671	32.73%	52,700,717	36.95%
Total Transmission Plant	$ 1,576,755,030	$ 581,602,944	36.89%	$ 515,077,669	32.67%	$ 581,602,944	36.89%
DISTRIBUTION PLANT							
Northern and Eastern Operations							
47100 Land Rights	$ 9,011,143	$ 3,046,141	33.80%	$ 2,863,242	31.77%	$ 2,673,340	29.67%
47200 Structures and Improvements	61,811,428	21,395,510	34.61%	13,896,700	22.48%	12,975,011	20.99%
47301 Services - Metallic	92,761,004	61,819,635	66.64%	56,609,660	61.03%	52,855,062	56.98%
47302 Services - Plastic	354,120,371	154,003,927	43.49%	122,483,288	34.59%	114,359,665	32.29%
47400 Regulators	27,055,553	11,323,841	41.85%	16,530,848	61.10%	16,530,848	61.10%
47401 Regulator and Meter Installations	29,092,211	10,143,131	34.87%	10,235,985	35.18%	9,557,090	32.85%
47501 Mains - Metallic	351,222,754	146,899,969	41.83%	239,955,259	68.32%	224,040,387	63.79%

UNION GAS LIMITED
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
47502 Mains - Plastic	201,072,312	71,688,284	35.65%	68,176,081	33.91%	63,654,348	31.66%
47700 Measuring and Regulating Equipment	103,778,777	50,944,049	49.09%	36,469,083	35.14%	34,050,296	32.81%
47800 Meters	52,403,372	16,508,017	31.50%	18,289,495	34.90%	17,076,457	32.59%
Total Northern and Eastern Operations	$ 1,282,328,925	$ 547,772,503	42.72%	$ 585,509,642	45.66%	$ 547,772,503	42.72%
Southern Operations							
47100 Land Rights	$ 5,494,304	$ 1,165,527	21.21%	$ 1,100,507	20.03%	$ 1,138,636	20.72%
47200 Structures and Improvements	101,589,573	46,066,298	45.35%	31,116,644	30.63%	32,194,731	31.69%
47301 Services - Metallic	109,632,954	101,160,672	92.27%	89,124,677	81.29%	92,212,547	84.11%
47302 Services - Plastic	741,618,024	291,246,443	39.27%	236,525,055	31.89%	244,719,851	33.00%
47400 Regulators	70,083,173	26,633,162	38.00%	39,811,017	56.81%	39,811,017	56.81%
47401 Regulator and Meter Installations	67,553,639	26,719,532	39.55%	21,266,239	31.48%	22,003,043	32.57%
47501 Mains - Metallic	399,123,055	212,172,022	53.16%	264,254,569	66.21%	273,410,100	68.50%
47502 Mains - Plastic	502,504,563	156,518,147	31.15%	151,729,785	30.19%	156,986,711	31.24%
47700 Measuring and Regulating Equipment	29,226,321	15,364,312	52.57%	10,911,016	37.33%	11,289,046	38.63%
47800 Meters	191,615,166	60,003,808	31.31%	61,165,077	31.92%	63,284,240	33.03%
Total Southern Operations	$ 2,218,440,772	$ 937,049,923	42.24%	$ 907,004,587	40.88%	$ 937,049,923	42.24%
Total Distribution Plant	$ 3,500,769,697	$ 1,484,822,426	42.41%	$ 1,492,514,229	42.63%	$ 1,484,822,426	42.41%
GENERAL PLANT							
Depreciable							
48200 Structures and Improvements	$ 41,903,606	$ 18,923,317	45.16%	$ 13,328,688	31.81%	$ 10,743,949	25.64%
48400 Transportation Equipment	44,635,164	11,532,184	25.84%	19,718,240	44.18%	15,894,419	35.61%
48500 Heavy Work Equipment	16,556,906	1,017,527	6.15%	5,157,062	31.15%	4,156,989	25.11%
Total Depreciable	$ 103,095,676	$ 31,473,028	30.53%	$ 38,203,991	37.06%	$ 30,795,357	29.87%
Amortizable							
48310 Office Furniture and Equipment	$ 11,113,877	$ 5,681,529	51.12%	$ 6,229,896	56.06%	$ 6,229,896	56.06%
48320 Office Equipment - Computers	86,088,725	49,191,303	57.14%	48,906,455	56.81%	48,906,455	56.81%
48601 Tools and Other Equipment	31,739,914	15,805,104	49.80%	15,893,892	50.08%	15,893,892	50.08%
48801 Communication Equipment	16,483,099	8,907,025	54.04%	9,232,388	56.01%	9,232,388	56.01%
Total Amortizable	$ 145,425,615	$ 79,584,960	54.73%	$ 80,262,631	55.19%	$ 80,262,631	55.19%
Total General Plant	$ 248,521,291	$ 111,057,988	44.69%	$ 118,466,622	47.67%	$ 111,057,988	44.69%
TOTALGAS UTILITY	$ 5,784,695,492	$ 2,406,759,893	41.61%	$ 2,332,031,324	40.31%	$ 2,406,759,893	41.61%

UNION GAS LIMITED
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
INTANGIBLE PLANT							
40100 Franchises and Consents	$ 1,218,909	$ 361,860	29.69%	$ -		$ 361,860	29.69%
Total Intangible Plant	$ 1,218,909	$ 361,860	29.69%	$ -		$ 361,860	29.69%
LOCAL STORAGE PLANT							
44200 Structures and Improvements	$ 2,674,066	$ 1,590,176	59.47%	$ 3,180	0.12%	$ 1,593,357	59.59%
44301 Gas Holders - Storage Tank	4,574,078	2,927,946	64.01%	5,856	0.13%	2,933,801	64.14%
44302 Gas Holders - Equipment	9,772,265	4,879,274	49.93%	(8,276)	-0.08%	4,870,999	49.85%
Total Local Storage Plant	$ 17,020,409	$ 9,397,396	55.21%	$ 760	0.00%	$ 9,398,157	55.22%
UNDERGROUND STORAGE PLANT							
45100 Land Rights	$ 32,062,296	$ 11,304,547	35.26%	$ -		$ 11,304,547	35.26%
45200 Structures and Improvements	55,119,051	25,607,371	46.46%	2,417,457	4.39%	28,024,828	50.84%
45300 Wells and Lines	87,601,565	35,795,372	40.86%	6,788,081	7.75%	42,583,453	48.61%
45600 Compressor Equipment	214,182,254	101,040,469	47.17%	5,464,989	2.55%	106,505,457	49.73%
45700 Measuring and Regulating Equipment	51,444,990	28,004,499	54.44%	3,093,734	6.01%	31,098,233	60.45%
Total Underground Storage Plant	$ 440,410,156	$ 201,752,258	45.81%	$ 17,764,260	4.03%	$ 219,516,518	49.84%
TRANSMISSION PLANT							
46100 Land Rights	$ 37,709,004	$ 8,678,444	23.01%	$ -		$ 8,678,444	23.01%
46200 Structures and Improvements	53,543,879	22,850,410	42.68%	2,209,823	4.13%	25,060,233	46.80%
46501 Mains - Metallic	1,041,972,208	335,943,553	32.24%	50,391,533	4.84%	386,335,086	37.08%
46600 Compressor Equipment	300,909,097	100,686,029	33.46%	8,142,435	2.71%	108,828,465	36.17%
46700 Measuring and Regulating Equipment	142,620,842	47,909,743	33.59%	4,790,974	3.36%	52,700,717	36.95%
Total Transmission Plant	$ 1,576,755,030	$ 516,068,178	32.73%	$ 65,534,766	4.16%	$ 581,602,944	36.89%
DISTRIBUTION PLANT							
Northern and Eastern Operations							
47100 Land Rights	$ 9,011,143	$ 2,673,340	29.67%	$ -		$ 2,673,340	29.67%
47200 Structures and Improvements	61,811,428	12,154,988	19.66%	820,023	1.33%	12,975,011	20.99%
47301 Services - Metallic	92,761,004	33,891,075	36.54%	18,963,987	20.44%	52,855,062	56.98%
47302 Services - Plastic	354,120,371	81,863,168	23.12%	32,496,497	9.18%	114,359,665	32.29%
47400 Regulators	27,055,553	16,530,848	61.10%			16,530,848	61.10%
47401 Regulator and Meter Installations	29,092,211	9,592,231	32.97%	(35,141)	-0.12%	9,557,090	32.85%
47501 Mains - Metallic	351,222,754	139,790,069	39.80%	84,250,318	23.99%	224,040,387	63.79%

UNION GAS LIMITED
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
47502 Mains - Plastic	201,072,312	45,467,391	22.61%	18,186,957	9.04%	63,654,348	31.66%
47700 Measuring and Regulating Equipment	103,778,777	22,798,993	21.97%	11,251,303	10.84%	34,050,296	32.81%
47800 Meters	52,403,372	16,884,195	32.22%	192,261	0.37%	17,076,457	32.59%
Total Northern and Eastern Operations	$ 1,282,328,925	$ 381,646,299	29.76%	$ 166,126,205	12.96%	$ 547,772,503	42.72%
Southern Operations							
47100 Land Rights	$ 5,494,304	$ 1,138,636	20.72%	$ -		$ 1,138,636	20.72%
47200 Structures and Improvements	101,589,573	29,314,529	28.86%	2,880,202	2.84%	32,194,731	31.69%
47301 Services - Metallic	109,632,954	56,747,151	51.76%	35,465,396	32.35%	92,212,547	84.11%
47302 Services - Plastic	741,618,024	173,102,150	23.34%	71,617,702	9.66%	244,719,851	33.00%
47400 Regulators	70,083,173	39,811,017	56.81%			39,811,017	56.81%
47401 Regulator and Meter Installations	67,553,639	22,050,886	32.64%	(47,843)	-0.07%	22,003,043	32.57%
47501 Mains - Metallic	399,123,055	172,683,322	43.27%	100,726,777	25.24%	273,410,100	68.50%
47502 Mains - Plastic	502,504,563	112,133,365	22.31%	44,853,346	8.93%	156,986,711	31.24%
47700 Measuring and Regulating Equipment	29,226,321	7,691,380	26.32%	3,597,667	12.31%	11,289,046	38.63%
47800 Meters	191,615,166	62,332,792	32.53%	951,448	0.50%	63,284,240	33.03%
Total Southern Operations	$ 2,218,440,772	$ 677,005,228	30.52%	$ 260,044,695	11.72%	$ 937,049,923	42.24%
Total Distribution Plant	$ 3,500,769,697	$1,058,651,527	30.24%	$ 426,170,899	12.17%	$ 1,484,822,426	42.41%
GENERAL PLANT							
Depreciable							
48200 Structures and Improvements	$ 41,903,606	$ 13,681,141	32.65%	$ (2,937,192)	-7.01%	$ 10,743,949	25.64%
48400 Transportation Equipment	44,635,164	15,799,426	35.40%	94,993	0.21%	15,894,419	35.61%
48500 Heavy Work Equipment	16,556,906	3,703,799	22.37%	453,190	2.74%	4,156,989	25.11%
Total Depreciable	$ 103,095,676	$ 33,184,365	32.19%	$ (2,389,009)	-2.32%	$ 30,795,357	29.87%
Amortizable							
48310 Office Furniture and Equipment	$ 11,113,877	$ 6,229,896	56.06%	$ -		$ 6,229,896	56.06%
48320 Office Equipment - Computers	86,088,725	48,906,455	56.81%			48,906,455	56.81%
48601 Tools and Other Equipment	31,739,914	15,893,892	50.08%			15,893,892	50.08%
48801 Communication Equipment	16,483,099	9,232,388	56.01%			9,232,388	56.01%
Total Amortizable	$ 145,425,615	$ 80,262,631	55.19%	$ -		$ 80,262,631	55.19%
Total General Plant	$ 248,521,291	$ 113,446,996	45.65%	$ (2,389,009)	-0.96%	$ 111,057,988	44.69%
TOTALGAS UTILITY	$ 5,784,695,492	$1,899,678,216	32.84%	$ 507,081,677	8.77%	$ 2,406,759,893	41.61%

UNION GAS LIMITED
Average Net Salvage

Statement E

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
40100 Franchises and Consents	$ 1,981,584	$ 762,675	$ 1,218,909			$ -	$ -	$ -	
Total Intangible Plant	$ 1,981,584	$ 762,675	$ 1,218,909			$ -	$ -	$ -	
LOCAL STORAGE PLANT									
44200 Structures and Improvements	$ 2,674,066	$ -	$ 2,674,066		-0.2%	$ -	$ (5,348)	$ (5,348)	-0.2%
44301 Gas Holders - Storage Tank	4,754,078	180,000	4,574,078		-0.2%		(9,148)	(9,148)	-0.2%
44302 Gas Holders - Equipment	10,066,067	293,802	9,772,265	-10.0%	-0.2%	(29,380)	(19,545)	(48,925)	-0.5%
Total Local Storage Plant	$ 17,494,211	$ 473,802	$ 17,020,409	-6.2%	-0.2%	$ (29,380)	$ (34,041)	$ (63,421)	-0.4%
UNDERGROUND STORAGE PLANT									
45100 Land Rights	$ 32,062,296	$ -	$ 32,062,296			$ -	$ -	$ -	
45200 Structures and Improvements	55,762,710	643,659	55,119,051	-43.9%	-10.0%	(282,566)	(5,511,905)	(5,794,471)	-10.4%
45300 Wells and Lines	88,526,941	925,376	87,601,565	-74.6%	-20.0%	(690,330)	(17,520,313)	(18,210,643)	-20.6%
45600 Compressor Equipment	234,191,224	20,008,970	214,182,254	-1.3%	-5.0%	(260,117)	(10,709,113)	(10,969,229)	-4.7%
45700 Measuring and Regulating Equipment	53,070,424	1,625,434	51,444,990	21.1%	-10.0%	342,967	(5,144,499)	(4,801,532)	-9.0%
Total Underground Storage Plant	$ 463,613,595	$ 23,203,439	$ 440,410,156	-3.8%	-8.8%	$ (890,047)	$ (38,885,830)	$ (39,775,877)	-8.6%
TRANSMISSION PLANT									
46100 Land Rights	$ 38,160,931	$ 451,927	$ 37,709,004			$ -	$ -	$ -	
46200 Structures and Improvements	54,109,649	565,770	53,543,879	-25.7%	-10.0%	(145,403)	(5,354,388)	(5,499,791)	-10.2%
46501 Mains - Metallic	1,059,797,242	17,825,034	1,041,972,208	-15.9%	-15.0%	(2,834,180)	(156,295,831)	(159,130,012)	-15.0%
46600 Compressor Equipment	315,158,985	14,249,888	300,909,097	24.8%	-5.0%	3,533,972	(15,045,455)	(11,511,483)	-3.7%
46700 Measuring and Regulating Equipment	149,158,521	6,537,679	142,620,842	-10.2%	-10.0%	(666,843)	(14,262,084)	(14,928,927)	-10.0%
Total Transmission Plant	$ 1,616,385,328	$ 39,630,298	$ 1,576,755,030	-0.3%	-12.1%	$ (112,454)	$ (190,957,758)	$ (191,070,212)	-11.8%
DISTRIBUTION PLANT									
Northern and Eastern Operations									
47100 Land Rights	$ 9,011,143	$ -	$ 9,011,143			$ -	$ -	$ -	
47200 Structures and Improvements	67,523,441	5,712,013	61,811,428	21.7%		1,239,507		1,239,507	1.8%
47301 Services - Metallic	96,125,200	3,364,196	92,761,004	-134.5%	-60.0%	(4,524,844)	(55,656,602)	(60,181,446)	-62.6%
47302 Services - Plastic	356,436,043	2,315,672	354,120,371	-52.7%	-40.0%	(1,220,359)	(141,648,148)	(142,868,508)	-40.1%
47400 Regulators	27,911,620	856,067	27,055,553						
47401 Regulator and Meter Installations	30,022,678	930,467	29,092,211	-5.9%		(54,898)		(54,898)	-0.2%
47501 Mains - Metallic	356,737,730	5,514,976	351,222,754	-44.7%	-60.0%	(2,465,194)	(210,733,652)	(213,198,847)	-59.8%
47502 Mains - Plastic	201,527,486	455,174	201,072,312	-40.4%	-40.0%	(183,890)	(80,428,925)	(80,612,815)	-40.0%
47700 Measuring and Regulating Equipment	107,761,746	3,982,969	103,778,777	-56.3%	-50.0%	(2,242,412)	(51,889,389)	(54,131,800)	-50.2%
47800 Meters	69,818,220	17,414,848	52,403,372	2.6%		452,786		452,786	0.6%
Total Northern and Eastern Operations	$ 1,322,875,307	$ 40,546,382	$ 1,282,328,925	-22.2%	-42.1%	$ (8,999,304)	$ (540,356,717)	$ (549,356,020)	-41.5%

UNION GAS LIMITED
Average Net Salvage

Statement E

Account Description	Additions	Retirements	Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Southern Operations									
47100 Land Rights	$ 5,494,304	$ -	$ 5,494,304			$ -	$ -	$ -	
47200 Structures and Improvements	119,052,665	17,463,092	101,589,573	25.8%		4,505,478		4,505,478	3.8%
47301 Services - Metallic	123,937,007	14,304,053	109,632,954	-38.0%	-60.0%	(5,435,540)	(65,779,772)	(71,215,313)	-57.5%
47302 Services - Plastic	755,754,308	14,136,284	741,618,024	-19.5%	-40.0%	(2,756,575)	(296,647,210)	(299,403,785)	-39.6%
47400 Regulators	75,400,868	5,317,695	70,083,173						
47401 Regulator and Meter Installations	72,104,842	4,551,203	67,553,639	-1.3%		(59,166)		(59,166)	-0.1%
47501 Mains - Metallic	411,129,872	12,006,817	399,123,055	-100.5%	-60.0%	(12,066,851)	(239,473,833)	(251,540,684)	-61.2%
47502 Mains - Plastic	506,075,977	3,571,414	502,504,563	-39.4%	-40.0%	(1,407,137)	(201,001,825)	(202,408,962)	-40.0%
47700 Measuring and Regulating Equipment	31,231,903	2,005,582	29,226,321	-66.6%	-50.0%	(1,335,718)	(14,613,161)	(15,948,878)	-51.1%
47800 Meters	238,983,324	47,368,158	191,615,166	3.6%		1,705,254		1,705,254	0.7%
Total Southern Operations	$ 2,339,165,070	$ 120,724,298	$ 2,218,440,772	-14.0%	-36.9%	$ (16,850,256)	$ (817,515,801)	$ (834,366,056)	-35.7%
Total Distribution Plant	$ 3,662,040,377	$ 161,270,680	$ 3,500,769,697	-16.0%	-38.8%	$ (25,849,559)	$ (1,357,872,517)	$ (1,383,722,076)	-37.8%
GENERAL PLANT									
Depreciable									
48200 Structures and Improvements	$ 44,105,715	$ 2,202,109	$ 41,903,606		20.0%	$ -	$ 8,380,721	$ 8,380,721	19.0%
48400 Transportation Equipment	119,294,853	74,659,689	44,635,164	23.3%	10.0%	17,395,708	4,463,516	21,859,224	18.3%
48500 Heavy Work Equipment	27,133,631	10,576,725	16,556,906	12.0%		1,269,207		1,269,207	4.7%
Total Depreciable	$ 190,534,199	$ 87,438,523	$ 103,095,676	21.3%	12.5%	$ 18,664,915	$ 12,844,238	$ 31,509,152	16.5%
Amortizable									
48310 Office Furniture and Equipment	$ 30,194,227	$ 19,080,350	$ 11,113,877			$ -	$ -	$ -	
48320 Office Equipment - Computers	352,823,042	266,734,317	86,088,725						
48601 Tools and Other Equipment	47,433,687	15,693,773	31,739,914						
48801 Communication Equipment	26,347,366	9,864,267	16,483,099						
Total Amortizable	$ 456,798,322	$ 311,372,707	$ 145,425,615			$ -	$ -	$ -	
Total General Plant	$ 647,332,521	$ 398,811,230	$ 248,521,291	4.7%	5.2%	$ 18,664,915	$ 12,844,238	$ 31,509,152	4.9%
TOTALGAS UTILITY	$ 6,408,847,616	$ 624,152,124	$ 5,784,695,492	-1.3%	-27.2%	$ (8,216,526)	$ (1,574,905,908)	$ (1,583,122,434)	-24.7%

UNION GAS LIMITED
Future Net Salvage
Local Storage

Statement F

Account Description	12/31/10 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
LOCAL STORAGE PLANT									
44200 Structures and Improvements	$ 2,674,066	$ 100,145	$ 2,573,921	-5.0%	0.0%	$ (5,007)	$ -	$ (5,007)	-0.2%
44301 Gas Holders - Storage Tank	4,574,078	171,336	4,402,742	-5.0%	0.0%	(8,567)	0	(8,567)	-0.2%
44302 Gas Holders - Equipment	9,772,265	359,531	9,412,734	-5.0%	0.0%	(17,977)	0	(17,977)	-0.2%
Total Local Storage Plant	$ 17,020,409	$ 631,012	$ 16,389,397	-5.0%	0.0%	$ (31,551)	$ -	$ (31,551)	-0.2%

UNION GAS LIMITED
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
40100 Franchises and Consents	20.00	SQ	20.00	15.16			24.00	SQ	24.12	12.90		
Total Intangible Plant									24.12	12.90		
LOCAL STORAGE PLANT												
44200 Structures and Improvements	2017	200-SC	45.56	14.21	-40.50	-41.4	2025	200-SC	30.51	14.23	-0.2	-0.2
44301 Gas Holders - Storage Tank	2017	200-SC	46.39	14.21	-15.90	-18.9	2025	200-SC	33.41	14.22	-0.2	-0.2
44302 Gas Holders - Equipment	2017	200-SC	42.67	14.22	-47.6	-47.6	2025	200-SC	25.78	14.23	-0.5	-0.2
Total Local Storage Plant									28.20	14.23	-0.4	
UNDERGROUND STORAGE PLANT												
45100 Land Rights	45.00	L2	45.02	38.49			45.00	L2	45.20	30.90		
45200 Structures and Improvements	2035	200-SC	45.53	31.13	-5.20	-5.0	2035	200-SC	40.66	23.71	-10.4	-10.0
45300 Wells and Lines	45.00	L2	45.52	36.43	-20.10	-20.0	45.00	L4	45.52	28.83	-20.6	-20.0
45600 Compressor Equipment	35.00	R5	35.08	21.75	-9.90	-10.0	35.00	R2.5	35.79	20.64	-4.7	-5.0
45700 Measuring and Regulating Equipment	25.00	R3	25.83	15.44	-8.8	-10.0	30.00	R3	31.18	15.95	-9.0	-10.0
Total Underground Storage Plant									37.89	22.31	-8.6	
TRANSMISSION PLANT												
46100 Land Rights	50.00	R4	50.00	42.35	0.80		55.00	R4	55.00	43.79		
46200 Structures and Improvements	40.00	R5	40.16	25.45	-4.80	-5.0	50.00	R5	50.06	31.14	-10.2	-10.0
46501 Mains - Metallic	50.00	R4	50.13	37.44	-17.20	-20.0	55.00	R4	55.16	39.41	-15.0	-15.0
46600 Compressor Equipment	30.00	S3	30.30	19.62	-4.90	-5.0	30.00	S3	30.27	21.30	-3.7	-5.0
46700 Measuring and Regulating Equipment	30.00	S1	30.11	22.34	-7.5	-10.0	40.00	S1.5	40.00	28.10	-10.0	-10.0
Total Transmission Plant									46.17	32.79	-11.8	
DISTRIBUTION PLANT												
Northern and Eastern Operations												
47100 Land Rights	60.00	L2	60.08	46.42			60.00	L2	60.30	41.14		
47200 Structures and Improvements	35.00	R4	35.63	22.29	-9.5	-10.0	40.00	R0.5	41.45	32.72	1.8	
47301 Services - Metallic	45.00	L3	45.01	30.83	-58.9	-60.0	50.00	R1.5	52.49	31.95	-62.6	-60.0
47302 Services - Plastic	55.00	L2	55.04	45.92	-74.5	-75.0	55.00	R3	55.09	41.45	-40.1	-40.0
47400 Regulators	30.00	R2.5	30.22	21.30	0.3		20.00	SQ	20.00	10.27		
47401 Regulator and Meter Installations	30.00	S1	30.35	21.41	-4.9	-5.0	35.00	R2.5	35.51	22.97	-0.2	
47501 Mains - Metallic	50.00	R4	49.98	37.18	-24.6	-25.0	55.00	R4	55.55	31.87	-59.8	-60.0

UNION GAS LIMITED
Current and Proposed Parameters
Vintage Group Procedure

Statement G

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
47502 Mains - Plastic	60.00	L2	60.05	49.67	-39.9	-40.0	60.00	L2	60.16	45.59	-40.0	-40.0
47700 Measuring and Regulating Equipment	28.00	S2	28.22	19.62	-28.7	-30.0	40.00	L1	40.63	31.07	-50.2	-50.0
47800 Meters	27.00	S1.5	27.21	17.91	1.9		25.00	L1.5	25.53	16.72	0.6	
Total Northern and Eastern Operations									48.80	33.41	-41.5	-42.1
Southern Operations												
47100 Land Rights	60.00	L2	60.01	52.38			60.00	L2	60.06	48.03		
47200 Structures and Improvements	35.00	R4	36.92	13.93	-1.3	-10.0	40.00	R0.5	42.74	30.82	3.8	
47301 Services - Metallic	45.00	L3	45.26	22.85	-62.3	-60.0	50.00	R1.5	54.07	27.02	-57.5	-60.0
47302 Services - Plastic	55.00	L2	55.02	46.96	-74.1	-75.0	55.00	R3	55.01	42.60	-39.6	-40.0
47400 Regulators	30.00	R2.5	30.41	21.07	1.1		20.00	SQ	20.00	10.33		
47401 Regulator and Meter Installations	30.00	S1	30.30	20.40	-4.6	-5.0	35.00	R2.5	35.12	24.04	-0.1	
47501 Mains - Metallic	50.00	R4	50.26	31.13	-25.0	-25.0	55.00	R4	55.48	32.28	-61.2	-60.0
47502 Mains - Plastic	60.00	L2	60.03	51.17	-39.9	-40.0	60.00	L2	60.09	47.13	-40.0	-40.0
47700 Measuring and Regulating Equipment	28.00	S2	28.42	18.50	-29.7	-30.0	40.00	L1	40.77	30.40	-51.1	-50.0
47800 Meters	27.00	S1.5	27.33	18.78	0.4		25.00	L1.5	25.54	17.51	0.7	
Total Southern Operations									47.02	33.25	-35.7	-42.1
Total Distribution Plant									47.65	33.31	-37.8	-38.8
GENERAL PLANT												
Depreciable												
48200 Structures and Improvements	2020	200-SC	39.71	17.09	18.8	20.0	2040	200-SC	47.65	28.35	19.0	20.0
48400 Transportation Equipment	7.00	L0.5	7.16	4.62	29.1	30.0	7.00	L1.5	7.31	4.10	18.3	10.0
48500 Heavy Work Equipment	15.00	L1	15.28	10.33	31.6	30.0	15.00	L1	14.99	10.83	4.7	
Total Depreciable									12.74	7.65	16.5	12.5
Amortizable												
48310 Office Furniture and Equipment	15.00	SQ	15.00	6.96			15.00	SQ	15.00	6.59		
48320 Office Equipment - Computers	4.00	SQ	4.00	2.14			4.00	SQ	4.00	1.73		
48601 Tools and Other Equipment	15.00	SQ	15.00	8.85			15.00	SQ	15.00	7.49		
48801 Communication Equipment	15.00	SQ	15.00	7.53			15.00	SQ	15.00	7.42		
Total Amortizable									5.71	2.60		
Total General Plant									7.40	3.81	4.9	5.2
TOTALGAS UTILITY									37.70	25.83	-24.7	-27.2

Analysis

Introduction

This section provides an explanation of the supporting schedules developed in the Union depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 47800S – Distribution Meters. Documentation for all other plant accounts is contained in the study work papers. The supporting schedules developed in the Union study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

Schedule A – Generation Arrangement

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 2. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

Schedule C – Plant History

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

Schedule D – Actuarial Life Analysis

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F - HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

UNION GAS LIMITED
Distribution
Southern Operations
Account: 47800S Meters

Dispersion: 25 - L1.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2010)	Surviving Plant (December 31, 2010)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2010	0.5	20,777,031	25.00	24.52	0.9806	1.0000	20,374,126	831,072
2009	1.5	12,389,967	25.00	23.56	0.9423	1.0000	11,675,089	495,572
2008	2.5	9,148,914	25.00	22.63	0.9049	1.0000	8,279,122	365,927
2007	3.5	7,209,704	25.00	21.72	0.8688	1.0000	6,263,688	288,389
2006	4.5	10,128,857	25.01	20.85	0.8336	1.0000	8,443,343	405,033
2005	5.5	8,478,288	25.00	20.01	0.8004	1.0000	6,785,867	339,170
2004	6.5	6,839,689	24.98	19.20	0.7689	1.0000	5,258,700	273,828
2003	7.5	8,080,575	25.04	18.44	0.7363	1.0000	5,949,417	322,682
2002	8.5	8,452,375	24.87	17.71	0.7120	1.0000	6,018,061	339,893
2001	9.5	7,085,137	24.86	17.01	0.6843	1.0000	4,848,462	285,018
2000	10.5	7,175,163	24.90	16.36	0.6568	1.0000	4,712,892	288,103
1999	11.5	7,539,720	24.90	15.75	0.6326	1.0000	4,769,909	302,826
1998	12.5	9,507,022	25.01	15.19	0.6075	1.0000	5,775,928	380,204
1997	13.5	6,365,640	25.37	14.68	0.5786	1.0000	3,682,929	250,919
1996	14.5	5,403,121	25.57	14.21	0.5556	1.0000	3,002,179	211,331
1995	15.5	11,290,823	25.72	13.77	0.5354	1.0000	6,045,281	438,975
1994	16.5	4,285,972	25.49	13.37	0.5244	1.0000	2,247,638	168,127
1993	17.5	4,439,612	25.94	12.99	0.5009	1.0000	2,223,767	171,129
1992	18.5	4,606,790	26.00	12.65	0.4864	1.0000	2,240,735	177,197
1991	19.5	5,226,828	26.39	12.32	0.4667	1.0000	2,439,598	198,063
1990	20.5	4,970,569	26.53	12.01	0.4526	1.0000	2,249,557	187,361
1989	21.5	3,970,905	26.65	11.71	0.4393	1.0000	1,744,492	148,979
1988	22.5	1,784,563	25.16	11.42	0.4540	1.0000	810,264	70,930
1987	23.5	2,738,588	27.55	11.15	0.4045	1.0000	1,107,856	99,402
1986	24.5	1,329,970	25.66	10.87	0.4238	1.0000	563,614	51,837
1985	25.5	1,415,134	26.22	10.60	0.4044	1.0000	572,266	53,963
1984	26.5	164,227	25.65	10.34	0.4030	1.0000	66,185	6,402
1983	27.5	1,083,980	28.27	10.08	0.3563	1.0000	386,262	38,337
1982	28.5	2,209,466	30.01	9.81	0.3270	1.0000	722,479	73,627
1981	29.5	1,003,015	29.35	9.55	0.3255	1.0000	326,457	34,179
1980	30.5	2,757,197	31.46	9.29	0.2954	1.0000	814,428	87,654
1979	31.5	786,807	29.06	9.03	0.3108	1.0000	244,560	27,075
1978	32.5	1,029,527	30.61	8.78	0.2867	1.0000	295,175	33,635
1977	33.5	949,696	30.71	8.52	0.2775	1.0000	263,549	30,928
1975	35.5	381,958	31.33	8.02	0.2561	1.0000	97,802	12,193
1972	38.5	93,294	34.60	7.30	0.2110	1.0000	19,681	2,697

UNION GAS LIMITED

Distribution

Southern Operations
Account: 47800S Meters

Dispersion: 25 - L1.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2010							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1971	39.5	170,681	35.52	7.07	0.1989	1.0000	33,956	4,805
1970	40.5	42,675	34.06	6.84	0.2008	1.0000	8,570	1,253
1968	42.5	3,037	35.65	6.40	0.1794	1.0000	545	85
1967	43.5	52,540	38.37	6.18	0.1611	1.0000	8,467	1,369
1966	44.5	7,255	38.26	5.97	0.1562	1.0000	1,133	190
1964	46.5	18,595	40.35	5.57	0.1380	1.0000	2,566	461
1962	48.5	7,970	41.88	5.18	0.1236	1.0000	986	190
1961	49.5	50,282	44.29	4.99	0.1127	1.0000	5,665	1,135
1951	59.5	335	54.73	3.32	0.0606	1.0000	20	6
1947	63.5	445	60.49	2.73	0.0452	1.0000	20	7
1929	81.5	11	75.72			1.0000		
1901	109.5	161,215	108.20			1.0000		
Total	10.9	$191,615,166	25.54	17.51	0.6857	1.0000	$131,383,285	$7,502,157

UNION GAS LIMITED

Distribution

Southern Operations

Account: 47800S Meters

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	1997 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2010	0.5	20,777,031		20,777,031	1.0000	0.5000
2009	1.5	12,401,298		12,389,967	0.9991	1.4995
2008	2.5	9,187,183		9,148,914	0.9958	2.4964
2007	3.5	7,277,245		7,209,704	0.9907	3.4869
2006	4.5	10,242,925		10,128,857	0.9889	4.4820
2005	5.5	8,789,045		8,478,288	0.9646	5.4525
2004	6.5	7,307,605		6,839,689	0.9360	6.4053
2003	7.5	8,455,498		8,080,575	0.9557	7.4303
2002	8.5	9,975,855		8,452,375	0.8473	8.2043
2001	9.5	8,300,745		7,085,137	0.8536	9.1281
2000	10.5	8,387,526		7,175,163	0.8555	10.0896
1999	11.5	9,076,148		7,539,720	0.8307	10.9773
1998	12.5	11,442,904		9,507,022	0.8308	11.9559
1997	13.5	7,171,244		6,365,640	0.8877	13.1653
1996	14.5		6,125,395	5,403,121	0.8821	14.1797
1995	15.5		12,680,543	11,290,823	0.8904	15.1191
1994	16.5		5,801,575	4,285,972	0.7388	15.6441
1993	17.5		5,423,388	4,439,612	0.8186	16.8141
1992	18.5		6,055,843	4,606,790	0.7607	17.5544
1991	19.5		6,796,465	5,226,828	0.7691	18.5962
1990	20.5		6,885,306	4,970,569	0.7219	19.3512
1989	21.5		5,328,549	3,970,905	0.7452	20.0566
1988	22.5		3,885,396	1,784,563	0.4593	19.1086
1987	23.5		3,810,609	2,738,588	0.7187	22.0130
1986	24.5		3,519,867	1,329,970	0.3778	20.6002
1985	25.5		3,151,458	1,415,134	0.4490	21.6170
1984	26.5		1,443,552	164,227	0.1138	21.4672
1983	27.5		1,961,020	1,083,980	0.5528	24.4784
1982	28.5		3,330,663	2,209,466	0.6634	26.5758
1981	29.5		2,280,158	1,003,015	0.4399	26.2497
1980	30.5		3,973,393	2,757,197	0.6939	28.6712
1979	31.5		3,392,567	786,807	0.2319	26.5638
1978	32.5		2,794,384	1,029,527	0.3684	28.3776
1977	33.5		2,695,086	949,696	0.3524	28.7194
1976	34.5		1,289,525		0.0000	24.5638
1975	35.5		1,538,094	381,958	0.2483	29.7657
1974	36.5		761,589		0.0000	29.7285

UNION GAS LIMITED
Distribution
Southern Operations
Account: 47800S Meters

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	1997 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1973	37.5		507,771		0.0000	30.3369
1972	38.5		459,584	93,294	0.2030	33.5440
1971	39.5		561,586	170,681	0.3039	34.6038
1970	40.5		547,894	42,675	0.0779	33.2639
1969	41.5		349,528		0.0000	33.6040
1968	42.5		261,891	3,037	0.0116	35.0669
1967	43.5		272,995	52,540	0.1925	37.8736
1966	44.5		238,905	7,255	0.0304	37.8319
1965	45.5		177,057		0.0000	37.5041
1964	46.5		183,463	18,595	0.1014	40.0504
1963	47.5		58,240		0.0000	38.1028
1962	48.5		92,237	7,970	0.0864	41.6778
1961	49.5		148,679	50,282	0.3382	44.1212
1960	50.5		111,642		0.0000	41.3618
1959	51.5		92,600		0.0000	41.3652
1958	52.5		24,569		0.0000	40.2199
1957	53.5		109		0.0000	40.0000
1956	54.5		75		0.0000	45.0000
1951	59.5		774	335	0.4327	54.7164
1950	60.5		155		0.0000	51.1568
1947	63.5		1,078	445	0.4131	60.4880
1929	81.5		99	11	0.1112	75.7231
1903	107.5		5,342		0.0000	95.5941
1901	109.5		1,170,372	161,215	0.1377	108.2008
Total	10.9	$138,792,252	$100,191,072	$191,615,166	0.8018	

UNION GAS LIMITED

Distribution Plant (North and South)

Account: 47800 Meters

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1997	136,333,799	8,933,032	1,550,639		143,716,192
1998	143,716,192	14,344,533	2,093,663		155,967,062
1999	155,967,062	11,296,028	2,227,148		165,035,942
2000	165,035,942	10,609,719	2,142,798	(753,655)	172,749,207
2001	172,749,207	11,588,165	3,665,128		180,672,245
2002	180,672,245	11,930,969	3,431,606		189,171,608
2003	189,171,608	10,370,426	4,433,385	(210,088)	194,898,561
2004	194,898,561	9,402,113	5,688,134		198,612,541
2005	198,612,541	11,047,559	4,436,217		205,223,883
2006	205,223,883	12,521,942	4,888,698		212,857,127
2007	212,857,127	9,209,991	4,978,716		217,088,402
2008	217,088,402	11,305,527	7,745,686		220,648,243
2009	220,648,243	17,431,236	8,623,676	750	229,456,552
2010	229,456,552	23,423,104	8,877,512	16,394	244,018,539

UNION GAS LIMITED

Distribution Plant (North and South)

Account: 47800 Meters

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1997	136,335,965	8,933,032	1,550,639		143,718,358
1998	143,718,358	14,344,533	2,093,663		155,969,227
1999	155,969,227	11,296,028	2,227,148		165,038,108
2000	165,038,108	10,609,719	2,142,798	(753,655)	172,751,373
2001	172,751,373	11,588,165	3,665,128		180,674,410
2002	180,674,410	11,855,941	3,431,606	(2,166)	189,096,580
2003	189,096,580	10,445,454	4,433,385	(210,088)	194,898,561
2004	194,898,561	9,436,606	5,688,134		198,647,033
2005	198,647,033	11,014,030	4,436,217		205,224,846
2006	205,224,846	12,529,447	4,888,698		212,865,595
2007	212,865,595	9,223,224	4,978,716		217,110,103
2008	217,110,103	11,540,371	7,745,686		220,904,788
2009	220,904,788	17,275,545	8,623,676	750	229,557,407
2010	229,557,407	23,322,250	8,877,512	16,394	244,018,539

UNION GAS LIMITED

Distribution Plant (North and South)

Account: 47800 Meters

T-Cut: None
Placement Band: 1901-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1997-2001	0.0	35.4	L0.5	14.19	29.1	L1.5 *	5.00	26.8	S1.5 *	1.55
1998-2002	0.0	33.3	L0.5	12.29	27.9	L1.5 *	4.38	26.3	S1.5 *	1.29
1999-2003	0.0	31.3	L0.5	10.22	27.0	L1.5 *	3.72	25.8	S1.5 *	1.11
2000-2004	0.0	28.9	L0.5	8.37	25.6	L1.5 *	3.25	24.8	S1.5 *	0.80
2001-2005	0.0	28.1	L0.5	7.31	25.6	L1.5 *	2.92	24.6	S1 *	0.69
2002-2006	0.0	28.0	L0.5	6.59	26.0	L1.5 *	2.81	24.8	S1 *	0.79
2003-2007	0.0	27.7	L0.5	6.39	26.2	L1.5 *	3.08	24.8	S0.5 *	0.90
2004-2008	0.0	26.5	L0.5	5.78	25.5	L1.5 *	3.35	24.1	S0.5 *	1.33
2005-2009	0.0	25.3	L0.5	4.32	25.0	L1 *	3.23	23.9	S0.5	1.67
2006-2010	0.0	23.9	L1	2.78	23.9	L1.5 *	2.47	23.3	S0	1.58

UNION GAS LIMITED
Distribution Plant (North and South)
Account: 47800 Meters

T-Cut: None
Placement Band: 1901-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1997-2010	0.0	27.1	L0.5	5.54	25.7	L1.5 *	2.77	25.2	L1.5 *	1.72
1999-2010	0.0	26.3	L0.5	4.91	25.3	L1.5 *	2.64	24.8	L1.5 *	1.51
2001-2010	0.0	25.4	L1	4.21	24.7	L1.5 *	2.55	24.2	L1.5	1.37
2003-2010	0.0	24.7	L1	3.54	24.4	L1.5 *	2.48	23.8	L1.5	1.42
2005-2010	0.0	24.5	L1	3.14	24.4	L1.5 *	2.59	23.7	S0	1.54
2007-2010	0.0	23.3	L1	2.40	23.3	L1	2.34	22.8	S0	1.64
2009-2010	0.0	22.1	L1.5 *	2.54	22.0	L1	2.27	21.9	L1	2.16

UNION GAS LIMITED
Distribution Plant (North and South)
Account: 47800 Meters

T-Cut: None
Placement Band: 1901-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

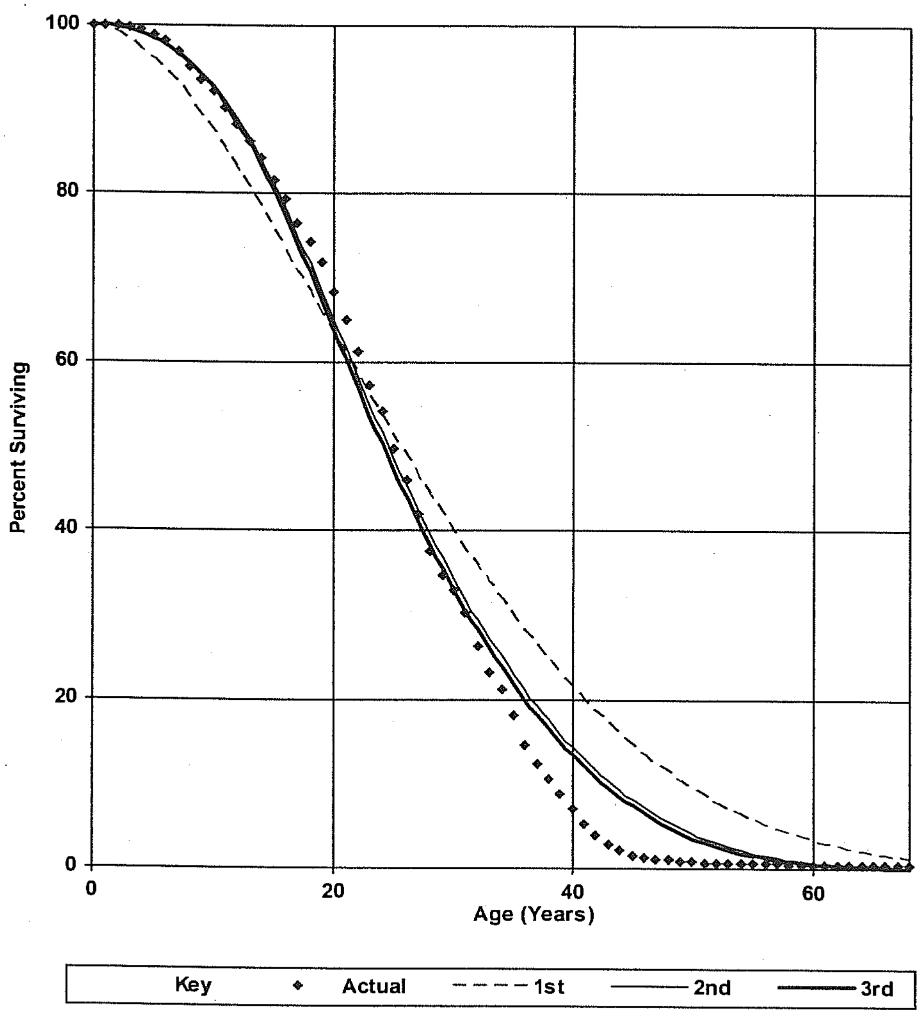
		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1997-1998	15.4	39.5	L0.5	13.97	32.4	L1.5 *	9.19	28.1	S1 *	11.12
1997-2000	0.2	38.5	L0.5	16.34	31.9	L1.5 *	6.32	28.3	S1 *	3.30
1997-2002	0.0	34.3	L0.5	12.98	28.5	L1.5 *	4.58	26.6	S1.5 *	1.41
1997-2004	0.0	31.3	L0.5	10.12	27.0	L1.5 *	3.52	25.7	S1 *	1.01
1997-2006	0.0	30.7	L0.5	9.05	27.2	L1.5 *	3.33	25.9	S1 *	0.82
1997-2008	0.0	29.3	L0.5	7.88	26.7	L1.5 *	3.28	25.6	S1 *	1.02
1997-2010	0.0	27.1	L0.5	5.54	25.7	L1.5 *	2.77	25.2	L1.5 *	1.72

UNION GAS LIMITED
Distribution Plant (North and South)
Account: 47800 Meters

T-Cut: None
Placement Band: 1901-2010 Observation Band: 1997-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

1st: 27.1-L0.5 2nd: 25.7-L1.5 3rd: 25.2-L1.5



UNION GAS LIMITED

Distribution Plant (North and South)

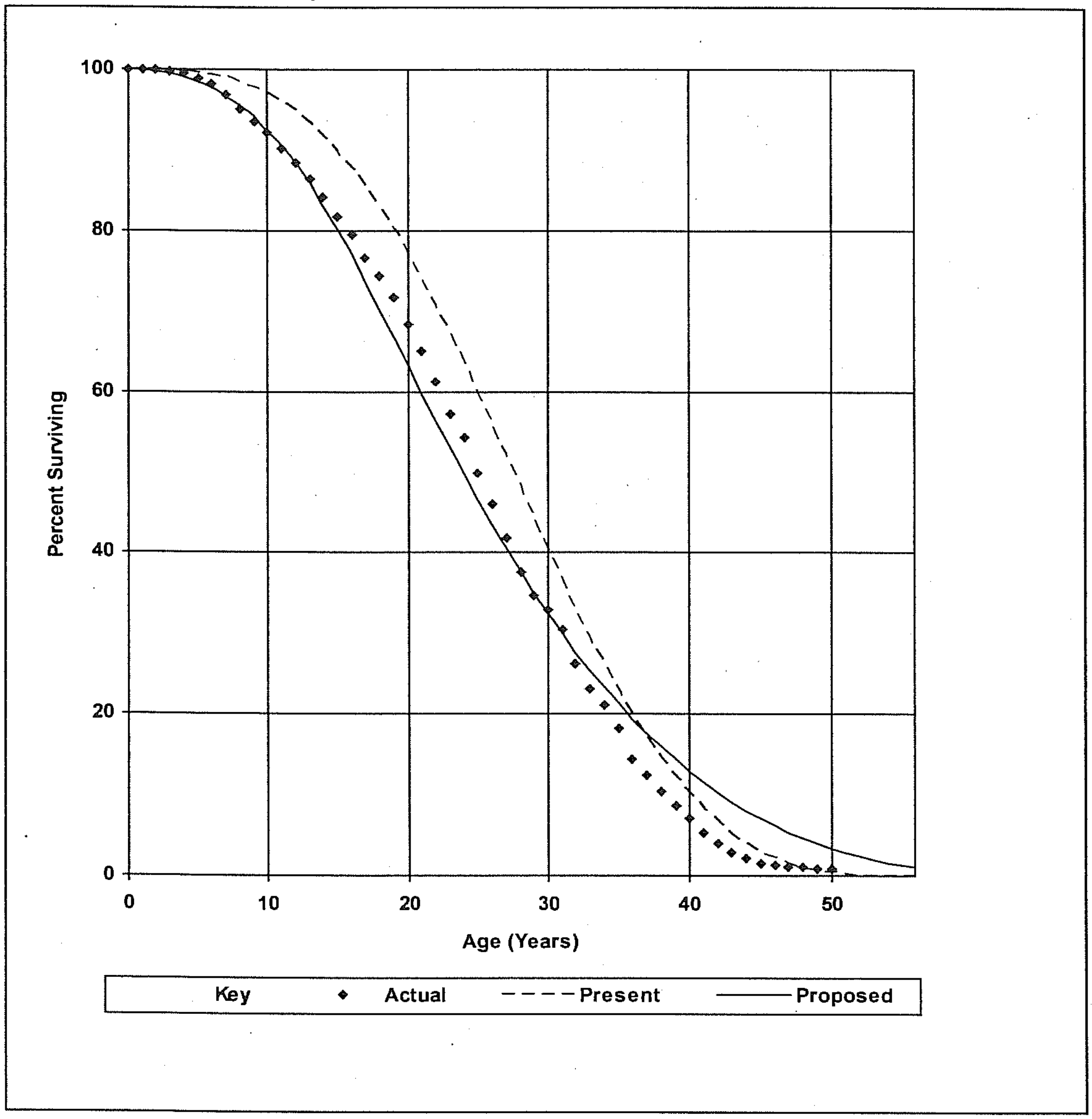
Account: 47800 Meters

T-Cut: 50

Placement Band: 1901-2010

Observation Band: 1997-2010

Present and Proposed Projection Life Curves Present: 27.0-S1.5 Proposed: 25.0-L1.5



UNION GAS LIMITED

Distribution Plant (North and South)

Account: 47800 Meters

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1997	1,550,639	79,666	5.1			0.0		79,666	5.1	
1998	2,093,663	113,857	5.4			0.0		113,857	5.4	
1999	2,227,148	94,959	4.3			0.0		94,959	4.3	
2000	2,142,798	63,180	2.9			0.0		63,180	2.9	
2001	3,665,128	323,002	8.8	5.8		0.0	0.0	323,002	8.8	5.8
2002	3,431,606	247,628	7.2	6.2		0.0	0.0	247,628	7.2	6.2
2003	4,433,385	220,927	5.0	6.0		0.0	0.0	220,927	5.0	6.0
2004	5,688,134	149,526	2.6	5.2		0.0	0.0	149,526	2.6	5.2
2005	4,436,217	153,292	3.5	5.1		0.0	0.0	153,292	3.5	5.1
2006	4,888,698	218,535	4.5	4.3		0.0	0.0	218,535	4.5	4.3
2007	4,978,716	136,606	2.7	3.6		0.0	0.0	136,606	2.7	3.6
2008	7,745,686	94,403	1.2	2.7		0.0	0.0	94,403	1.2	2.7
2009	8,623,676	161,693	1.9	2.5		0.0	0.0	161,693	1.9	2.5
2010	8,877,512	93,665	1.1	2.0		0.0	0.0	93,665	1.1	2.0
Total	64,783,005	2,150,940	3.3			0.0		2,150,940	3.3	

UNION GAS LIMITED

Distribution Plant (North and South)

Account: 47800 Meters

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1997	1,550,639	79,666	5.1			0.0		79,666	5.1	
1998	2,093,663	113,857	5.4			0.0		113,857	5.4	
1999	2,227,148	94,959	4.3			0.0		94,959	4.3	
2000	2,142,798	63,180	2.9			0.0		63,180	2.9	
2001	3,665,128	323,002	8.8	5.8		0.0	0.0	323,002	8.8	5.8
2002	3,431,606	247,628	7.2	6.2		0.0	0.0	247,628	7.2	6.2
2003	4,433,385	220,927	5.0	6.0		0.0	0.0	220,927	5.0	6.0
2004	5,688,134	149,526	2.6	5.2		0.0	0.0	149,526	2.6	5.2
2005	4,436,217	153,292	3.5	5.1		0.0	0.0	153,292	3.5	5.1
2006	4,888,698	218,535	4.5	4.3		0.0	0.0	218,535	4.5	4.3
2007	4,978,716	136,606	2.7	3.6		0.0	0.0	136,606	2.7	3.6
2008	7,745,686	94,403	1.2	2.7		0.0	0.0	94,403	1.2	2.7
2009	8,623,676	161,693	1.9	2.5		0.0	0.0	161,693	1.9	2.5
2010	8,877,512	93,665	1.1	2.0		0.0	0.0	93,665	1.1	2.0
Total	64,783,005	2,150,940	3.3			0.0		2,150,940	3.3	

UNION GAS LIMITED
Comparison of Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Forecast 2013	Forecast 2012	Difference	
		(a)	(b)	(c)	
1	Cost of gas	697,838	721,228	(23,390)	/u
2	Operating and maintenance	393,228	383,774	9,454	/u
3	Depreciation	196,467	204,145	(7,678)	
4	Other financing	1,179	362	817	
5	Property taxes	64,022	62,916	1,106	
6	Other expense	-	-	-	
7	Income taxes	6,574	18,560	(11,986)	/u
8	Cost of service excluding return	1,359,308	1,390,985	(31,676)	/u

UNION GAS LIMITED
Gas Purchase Expense
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	94,306	194,446	
2	U.S. Firm	43,546	20,475	
3	Adjustments	-	(105)	
4	Total Supply Transport	137,852	214,817	
	Supply Commodity			
5	Western Canadian Firm	75,809	346,611	49%
6	U.S. Firm	43,546	223,660	28%
7	Ontario Delivered Supplies	16,356	88,742	11%
8	Northern Bundled T-Service	18,497	-	12%
9	Adjustments	-	-	0%
10	Other	-	-	0%
11	Total Supply Commodity	154,208	659,013	100%
	Storage			
12	STS and Related Services		19,874	
13	Total Supply at Cost		893,703	
Section B				
	Storage Inventory Change			
14	LNG	-	-	
15	Other Company Owned	(1,596)	(8,569)	
16	3rd Party	-	-	
17	Total Gas (to) from Storage	(1,596)	(8,569)	
Section C				
18	Total Third Party Storage		425	
19	Total Section A, B, & C		885,559	

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	894,128	
2	Deferred Costs		(135,680)	
3	Total Gas Supply	154,208	758,448	
4	Gas (to) from Storage	(1,596)	(8,569)	
5	Winter Peaking Service		-	
6	Other Transportation		972	
7	Company Use Adj.		(1,960)	
8	Linepack		(32)	
9	Deferral Adjustment		(42,790)	
10	UFG Adjustment		(7,671)	/u
11	Accounting Adjustment		-	
12	Total Cost of Gas	152,613	698,398	/u
13	Less: Unregulated costs		(2,252)	/u
14			696,146	/u
15	Add: Costs related to short-term storage revenue		1,692	/u
16	Total Utility Cost of Gas		697,838	/u

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2013

Line No.	Particulars	Volume (a)	Weighting (b)	Volume Weighted (c)	
	Determination of Forecast UFG volume for 2013				
	3 year average of actual UFG (10^3m^3):				
1	2011	35,668	50%	17,834	/u
2	2010	67,283	33%	22,203	/u
3	2009	201,845	17%	34,314	/u
4	Average actual UFG volume			74,351	/u
	3 year average of actual throughput (10^6m^3):				
5	2011	33,824	50%	16,912	/u
6	2010	35,090	33%	11,580	/u
7	2009	31,677	17%	5,385	/u
8	Average actual UFG throughput			33,877	/u
9	UFG ratio for 2013 (line 4 / line 8 / 1,000)			0.219%	/u
10	2013 total forecast throughput (10^6m^3)			32,010	
11	Estimated UFG volume for 2013 (10^3m^3) (1)			70,253	/u
12	Estimated UFG for 2013 ($000's) (2)			14,234	/u
13	Unregulated Allocation - Short-Term ($000's)		2.514%	(358)	/u
14	Unregulated Allocation - Long-Term ($000's)		7.036%	(1,001)	/u

Note:
(1) Line 9 * line 10 * 1,000.
(2) Calculated using EB-2010-0359 reference price of $202.61/10^3m^3$.

UNION GAS LIMITED
Gas Supply / Demand Balance
Forecast 2012 to 2016

Line No.	Particulars (TJ)	2012	2013	2014	2015	2016
		(a)	(b)	(c)	(d)	(e)
1	Forecasted Demand [1]	234,413	226,432	225,108	225,108	225,108
2	Other Demand	4,062	4,269	4,489	4,488	4,454
3	Total Demand Served	238,475	230,701	229,597	229,596	229,562
	Total Supply					
4	Western Canadian Firm	107,848	107,522	107,247	104,185	70,863
5	U.S. Firm	43,884	43,639	43,466	42,461	18,363
6	Ontario Delivered Supplies	83,306	79,779	77,916	81,664	133,103
7	Local Production	1,021	1,018	1,018	1,018	1,021
8	Inventory Withdrawals/(Injections)	2,416	(1,257)	(51)	267	6,213
9	Total	238,475	230,701	229,597	229,596	229,562

Note:
(1) Forecasted demand includes Sales Service and Bundled T-service Demands and Supplies. Excludes Northern T-Service, T1 & T3 Volumes.

UNION GAS LIMITED
Calculation of Alberta Border and Ontario Landed Reference Prices
For the 12 month period ending December 31, 2011

Line No.	Particulars		Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total or Average
1	Days		31	28	31	30	31	30	31	31	30	31	30	31	365
2	NYMEX 21 Day Average (US$/mmbtu)	(1)	4.211	4.221	4.189	4.159	4.190	4.241	4.303	4.347	4.365	4.444	4.667	4.974	4.359
3	Empress Basis (US$/mmbtu)		(0.620)	(0.640)	(0.611)	(0.607)	(0.607)	(0.607)	(0.607)	(0.607)	(0.607)	(0.607)	(0.550)	(0.550)	(0.602)
4	Foreign Exchange		1.013	1.014	1.015	1.016	1.016	1.018	1.018	1.019	1.020	1.021	1.022	1.023	1.018
5	Alberta Border (Cdn$/GJ)	(2)	3.449	3.442	3.442	3.418	3.452	3.505	3.567	3.613	3.633	3.713	3.988	4.290	3.626
	North Supply Cost Calculation														
6	Total Volume (PJ)		3.469	3.103	3.465	3.321	3.441	3.316	3.437	3.429	3.313	3.437	3.312	3.436	40.48
7	Cost at Market Price ($000's)		11,963	10,678	11,926	11,352	11,878	11,622	12,261	12,389	12,037	12,761	13,208	14,739	146,814
8	Weighted Average Price (Cdn$/GJ)														3.627
9														Alberta Border Reference Price (Cdn$/GJ)	3.627
10														Add : Fuel (Cdn$/GJ)	0.105
11														Add : Tolls (Cdn$/GJ)	1.638
12														Ontario Landed Reference Price (Cdn$/GJ)	5.370

Note:
(1) 21 Day Strip dates used - November 1, 2010 to December 1, 2010.
(2) Alberta Border Price = ((NYMEX 21-day Average + Empress Basis) * (Foreign Exchange Rate))/MMBtu to GJ Conversion Rate.
MMBtu to GJ Conversion Rate: 1.055056 GJ /MMBtu.

UNION GAS LIMITED
Summary of Upstream Transportation Contracts - Effective November 1, 2011
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point (a)	Primary Delivery Point (b)	Contract Quantity (c)	Contract Units (d)	Contract Termination Date (e)	Unitized Demand Charge ($Cdn/GJ) (f)	Commodity Charge ($Cdn/GJ) (g)	100% LF Toll ($Cdn/GJ) (h=f+g)
	TransCanada Pipeline								
1	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	01-Nov-2012	2.099	0.144	2.243
2	Empress to Union EDA FT	Empress	Union EDA	8,675	GJ	01-Nov-2012	2.099	0.144	2.243
3	Empress to Union NDA FT	Empress	Union NDA	67,625	GJ	01-Jan-2013	1.632	0.110	1.742
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	01-Jan-2013	1.062	0.071	1.133
5	Empress to Union SSMDA FT	Empress	Union SSMDA	9,143	GJ	01-Jan-2013	1.632	0.110	1.742
6	Empress to Union EDA FT	Empress	Union EDA	50,576	GJ	01-Jan-2013	2.099	0.144	2.243
7	Empress to Union NCDA FT	Empress	Union NCDA	9,211	GJ	01-Jan-2013	2.099	0.144	2.243
8	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	01-Jan-2013	0.639	0.041	0.680
9	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	01-Nov-2016	0.268	0.015	0.284
10	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	01-Nov-2017	0.268	0.015	0.284
11	Parkway to Union CDA FT-NR	Parkway	Union CDA	64,000	GJ	01-Nov-2012	0.068	0.001	0.069
12	Parkway to Union CDA FT	Parkway	Union CDA	16,000	GJ	01-Nov-2012	0.068	0.001	0.069
13	TCPL FT - Total			306,177	GJ				
	TransCanada Storage Transportation Service Firm Withdrawal								
14	NCDA	Parkway	Union NCDA	13,704	GJ	01-Jan-2013			
15	WDA	Parkway	Union WDA	31,420	GJ	01-Jan-2013			
16	SSMDA	Dawn	Union SSMDA	35,022	GJ	01-Jan-2013			
17	NDA	Parkway	Union NDA	48,375	GJ	01-Jan-2013			
18	EDA	Parkway	Union EDA	68,520	GJ	01-Jan-2013	0.263	0.018	0.281
19	TCPL Firm STS Withdrawal - Total			197,041	GJ				
	TransCanada Storage Transportation Service Firm Injection								
20	NCDA	Union NCDA	Parkway	0	GJ	01-Jan-2013		0.009	0.009
21	WDA	Union WDA	Parkway	3,150	GJ	01-Jan-2013	1.033	0.069	1.102
22	SSMDA	Union SSMDA	Parkway	0	GJ	01-Jan-2013			
23	EDA	Union EDA	Parkway	47,571	GJ	01-Jan-2013			
24	NDA	Union NDA	Parkway	49,100	GJ	01-Jan-2013	0.405	0.025	0.430
25	TCPL Firm STS Injection - Total			99,821	GJ				
	Michigan Consolidated Gas Company (MichCon)/Great Lakes Gas Transmission (GLGT)/TransCanada Pipeline (TCPL)								
26	TCPL to Union SSMDA	S.S. Marie	Union SSMDA	6,143	GJ	01-Nov-2014			
27	GLGT to TCPL	Belle River Mills	S.S. Marie	5,829	DTH	01-Nov-2014			
28	MichCon to GLGT	MichCon Generic	Belle River Mills	5,829	DTH	01-Nov-2014			
29	MichCon/GLGT/TCPL FT - Total			6,143	GJ		0.171	0.001	0.172
	Centra Transmission Holdings Inc.								
30	Centra Transmission Holdings Inc.	Spruce	Union MDA	8,000	MCF	01-Nov-2012			
31	Centra Pipelines Minnesota Inc.	Sprague	Baudette	8,000	MCF	01-Nov-2012			
32	CTHI FT - Total			8,473	GJ		0.230		0.230

UNION GAS LIMITED
Summary of Upstream Transportation Contracts - Effective November 1, 2011
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date	Unitized Demand Charge ($Cdn/GJ)	Commodity Charge ($Cdn/GJ)	100% LF Toll ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h=f+g)
	TransCanada Pipeline								
1	Dawn to Union CDA FT	Dawn	Union CDA	60,000	GJ	01-Nov-2012	0.210	0.011	0.221
2	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	01-Feb-2013	2.099	0.144	2.243
3	Empress to Union CDA FT	Empress	Union CDA	13,149	GJ	01-Nov-2012	2.099	0.144	2.243
4	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	01-Nov-2012	2.099	0.144	2.243
5	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	01-Jan-2013	2.099	0.144	2.243
6	Empress to Union CDA FT	Empress	Union CDA	12,500	GJ	01-Jan-2016	2.099	0.144	2.243
7	TCPL FT - Total			131,327	GJ				
	Alliance Pipelines/Vector Pipelines								
8	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	01-Dec-2015			
9	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	01-Dec-2015			
10	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	01-Dec-2015			
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	01-Dec-2015			
12	Alliance/Vector - Total			84,405	GJ		1.665	0.002	1.666
	Panhandle Eastern Pipe Line Field Zone								
13	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	01-Nov-2017			
14	PEPL - Total			26,376	GJ		0.411	0.043	0.453
	Trunkline Gas Company/Panhandle Eastern Pipe Line								
15	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	01-Nov-2012			
16	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	01-Nov-2012			
17	TGC/PEPL FT - Total			21,101	GJ		0.184	0.027	0.210
	Vector Pipelines								
18	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	81,000	DTH	01-Dec-2015			
19	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	85,460	GJ	01-Dec-2015			
20	Vector - Total			85,460	GJ		0.242	0.002	0.243
	Other:								
21	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	200,000	MCF	01-Nov-2012			
22				213,479	GJ		0.004		0.004
23	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	115,000	MCF	01-Nov-2012			
24				122,750	GJ		0.014		0.014
25	TransCanada Pipeline [(1)]	Niagara	Kirkwall	21,101	GJ	01-Nov-22	0.126		0.126
26				21,101	GJ				

Exchange Rate 1 US =	0.981354269	CAD
Conversion Factor	1.055056	

Note:
(1) Contract start date is November 1, 2012

UNION GAS LIMITED
Allocation of Assets (Storage) - Southern Operations Area
(Based on April 1, 2012 to March 31, 2013 - for the 2013 Test Year)
($10^3 m^3$)

Line No.	Rate Class	Aggregate Excess Storage		SPS Adjustment	Net Aggregate Excess Storage	Infranchise Factor	Class Allocation
		(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = (d) * (e)
1	M1/M2 Res	603,805		(83,914)	519,891	100.00%	519,891
2	M1/M2 Comm./Ind.	501,733		(69,728)	432,005	100.00%	432,005
3	M2 Total		1,105,538	(153,642)	951,896	100.00%	951,896
4	M4		37,133		37,133	100.00%	37,133
5	M5A		60,008		60,008	100.00%	60,008
6	M7		15,051		15,051	100.00%	15,051
7	M9		7,725		7,725	100.00%	7,725
8	M10		15		15	100.00%	15
9	Total		1,225,469	(153,642)	1,071,827		1,071,827

10 The average number of M1/M2 residential customers: 897,471.
11 For residential customers: storage space per customer will equal 579 m^3.

12 The annual forecast volume for all M1/M2 commercial / industrial winter peak customers: 1,713,633 $10^3 m^3$.
13 For non-contract commercial / industrial customers: storage space per customer will equal 25% of their annual weather normalized volume.

14 SPS entitlement: 16% of applicable customer's SSS entitlement.

15 The Global Proration Infranchise Factor, which was previously applied to the storage entitlement calculated for customers who were migrating to T1/T3 or
16 unbundling service has been removed as a result of the Natural Gas Storage Allocations Policy hearing Decision (EB-2007-0724/0725).

UNION GAS LIMITED
Allocation of Assets - (Storage and Transportation) - Northern and Eastern Operations Area
As of November 2012 - For 2013

Line No.	Particulars	TCPL FT Pipe (10^3m^3/day) (a)	Redelivery (10^3m^3/day) (b)	Delivery (10^3m^3/day) (c)	Storage (10^6m^3) (d)
	Central Delivery Area				
1	Residential 01	107.5	362.7	61.1	16.8
2	Commercial 01	47.4	166.5	34.0	7.4
3	Commercial/Industrial 10	79.6	250.3	26.6	12.5
4	Rate 20	0.0	0.0	0.0	0.0
5	Total	234.5	779.6	121.6	36.7
	Eastern Delivery Area				
6	Residential 01	711.3	1,012.1	625.0	61.6
7	Commercial 01	251.8	377.1	238.7	21.8
8	Commercial/Industrial 10	416.0	534.9	313.2	36.0
9	Rate 20	189.3	90.5	54.0	5.9
10	Total	1,568.4	2,014.5	1,230.9	125.3
	Northern Delivery Area				
11	Residential 01	708.5	1,470.3	516.2	75.2
12	Commercial 01	250.9	544.6	204.7	26.6
13	Commercial/Industrial 10	313.3	614.3	196.4	33.3
14	Rate 20	19.4	15.8	7.4	0.6
15	Total	1,292.1	2,644.9	924.7	135.7
	Sault Ste. Marie Delivery Area				
16	Residential 01	99.2	395.1	0.0	18.3
17	Commercial 01	36.1	149.4	0.0	6.6
18	Commercial/Industrial 10	68.7	214.3	0.0	9.6
19	Rate 20	13.1	17.8	0.0	0.6
20	Total	217.1	776.6	0.0	35.1
	Western Delivery Area				
21	Residential 01	513.4	494.4	46.9	31.2
22	Commercial 01	153.7	159.7	15.2	9.3
23	Commercial/Industrial 10	208.7	183.2	17.4	9.0
24	Rate 20	99.4	48.0	4.5	3.1
25	Total	975.2	885.3	84.0	52.6
	Manitoba Delivery Area				
26	Residential 01	72.0	4.0	0.0	0.9
27	Commercial 01	27.5	1.5	0.0	0.3
28	Commercial/Industrial 10	21.1	1.2	0.0	0.2
29	Rate 20	0.0	0.0	0.0	0.0
30	Total	120.6	6.7	0.0	1.4
	Total				
31	Residential 01	2,211.9	3,738.7	1,249.2	204.0
32	Commercial 01	767.5	1,398.8	492.5	72.0
33	Commercial/Industrial 10	1,107.3	1,798.1	553.6	100.6
34	Rate 20	321.2	172.1	65.9	10.2
35	Total	4,407.8	7,107.7	2,361.2	386.8

UNION GAS LIMITED
Allocation of Northern Assets
For 2013 Test Year

Line No.	Particulars	TCPL FT Allocation (a)	Redelivery Allocation (b)	Delivery Allocation (c)	Storage Allocation (d)
	Central Delivery Area				
1	* Residential 01	4.6	15.5	2.6	721.5
2	** Commercial 01	75.6%	264.8%	54.0%	32.3%
3	** Commercial/Industrial 10	75.6%	237.1%	25.2%	32.3%
	Eastern Delivery Area				
4	* Residential 01	8.2	11.6	7.2	707.0
5	** Commercial 01	143.2%	213.9%	135.4%	33.8%
6	** Commercial/Industrial 10	143.3%	183.7%	107.6%	33.9%
	Northern Delivery Area				
7	* Residential 01	7.5	15.5	5.4	792.8
8	** Commercial 01	110.3%	238.8%	89.7%	31.9%
9	** Commercial/Industrial 10	110.4%	215.8%	69.0%	32.0%
	Sault Ste. Marie Delivery Area				
10	* Residential 01	4.1	16.2	0.0	749.8
11	** Commercial 01	67.7%	279.5%	0.0%	34.0%
12	** Commercial/Industrial 10	67.7%	210.8%	0.0%	25.8%
	Western Delivery Area				
13	* Residential 01	9.8	9.5	0.9	597.2
14	** Commercial 01	141.6%	146.7%	13.9%	23.4%
15	** Commercial/Industrial 10	126.5%	110.8%	10.5%	15.0%
	Manitoba Delivery Area				
16	* Residential 01	8.8	0.5	0.0	103.7
17	** Commercial 01	290.7%	16.1%	0.0%	9.4%
18	** Commercial/Industrial 10	291.5%	16.2%	0.0%	9.4%

Note:

(*) Rate 01 Residential allocation is in m^3/day/customer for FT, Redelivery and Delivery.
For storage, the allocation is in m^3.

(**) Rate 01 and 10 Commercial allocations are shown as a percentage of avgerage day volume.

UNION GAS LIMITED
Operating and Maintenance Expense by Administrator
Calender Year Ending December 31

Line No.	Particulars ($000's)	Forecast 2013	
1	Affiliate Services (Inbound & Outbound)	(1,818)	
2	Audit Services	487	
3	Bad Debt Expense	6,600	
4	Business Development, Storage & Transmission	16,615	
5	Corporate Adjustments	2,832	/u
6	Distribution Operations	127,776	
7	Employee & Labour Relations	108,123	/u
8	Energy Conservation	31,843	
9	Engineering, Construction & STO	47,590	
10	Environment, Health & Governance	887	
11	Executive	3,281	
12	Finance	10,742	
13	Government Affairs / Relations	993	
14	Insurance	9,484	
15	IT - Information Systems	12,009	
16	IT - Information Technology Infrastructure	14,832	
17	IT - Other	2,806	
18	Legal	1,407	
19	Marketing & Customer Care	62,914	
20	Procurement / Supply Chain	2,078	
21	Project Systems & Controls	209	
22	Regulatory, Municipal Relations and Public Affairs	16,982	
23	Tax	1,209	
24	Total	479,881	/u
25	Capitalization	(73,028)	/u
26	Non-Utility Allocation	(13,625)	/u
27	Total Net Utility Operating and Maintenance Expense	393,228	/u
28	Excess Utility Cross-Charge	(2,261)	
29	Total Net Utility O&M Less Cross-Charge	390,967	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Test vs. 2012 Forecast

Line No.	Particulars ($000's)	Forecast 2013	Forecast 2012	Difference	%	
		(a)	(b)	(c)	(d)	
1	Salaries/Wages	193,787	187,950	5,837	3.11%	
2	Benefits	81,083	82,161	(1,078)	(1.31%)	/u
3	Materials	9,958	9,242	716	7.75%	
4	Employee Expenses/Training	14,330	14,110	220	1.56%	
5	Contract Services	66,376	63,670	2,706	4.25%	
6	Consulting	13,172	11,082	2,090	18.86%	
7	General	22,190	21,592	598	2.77%	
8	Transportation and Maintenance	9,761	9,375	386	4.12%	/u
9	Company Used Gas	2,501	2,473	28	1.13%	
10	Utility Costs	4,682	4,562	120	2.63%	
11	Communications	6,380	6,243	137	2.19%	
12	Demand Side Management Programs	24,232	23,605	627	2.66%	
13	Advertising	2,386	2,288	98	4.29%	
14	Insurance	9,056	8,605	451	5.24%	
15	Donations	788	775	13	1.68%	
16	Financial	1,871	1,860	11	0.57%	
17	Lease	4,191	4,151	40	0.96%	
18	Cost Recovery from Third Parties	(2,549)	(2,883)	334	(11.58%)	
19	Computers	6,465	6,158	307	4.98%	
20	Regulatory Hearing & OEB Cost Assessment	4,300	5,200	(900)	(17.31%)	
21	Outbound Affiliate Services	(13,706)	(13,667)	(39)	0.29%	
22	Inbound Affiliate Services	11,888	11,494	394	3.43%	
23	Bad Debt	6,600	6,600	-	0.00%	
24	Other	139	141	(2)	(1.07%)	
25	Total Gross Operating and Maintenance Expense	479,881	466,787	13,094	2.81%	/u
26	Indirect Capitalization	(51,376)	(50,789)	(587)	1.16%	/u
27	Direct Capitalization	(21,652)	(19,019)	(2,633)	13.84%	/u
28	Total Utility Operating and Maintenance Expense	406,853	396,979	9,874	2.49%	/u
29	Non-Utility Allocations	(13,625)	(13,205)	(420)	3.18%	/u
30	Total Net Utility Operating and Maintenance Expense	393,228	383,774	9,454	2.46%	/u
31	Excess Utility Cross-Charge	(2,261)	(2,261)	-	0.00%	
32	Total Net Utility O&M Less Cross-Charge	390,967	381,513	9,454	2.46%	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Salaries / Wages	
1	2013 Forecast	193,787
2	2012 Forecast	187,950
3	Difference	5,837
	Reasons:	
4	Merit increase	6,900
5	Market Development - Energy Technology and Innovation Canada	100
6	Other	(1,163)
7	Total difference: 2013 Forecast vs. 2012 Forecast	5,837
	Benefits	
8	2013 Forecast	61,684
9	2012 Forecast	72,269
10	Difference	(10,585)
	Reasons:	
11	Increased non pension benefit costs	1,441
12	Decreased pension benefit costs	(12,026)
13	Total difference: 2013 Forecast vs. 2012 Forecast	(10,585)
	Materials	
14	2013 Forecast	9,958
15	2012 Forecast	9,242
16	Difference	716
	Reasons:	
17	Other	716
18	Total difference: 2013 Forecast vs. 2012 Forecast	716

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Employee Expenses / Training	
1	2013 Forecast	14,330
2	2012 Forecast	14,110
3	Difference	220
	Reasons:	
4	Travel	83
5	Training	125
6	Other	12
7	Total difference: 2013 Forecast vs. 2012 Forecast	220
	Contract Services	
8	2013 Forecast	66,376
9	2012 Forecast	63,670
10	Difference	2,706
	Reasons:	
11	Pipeline integrity	900
12	Line locates	583
13	Banner transactional fee	300
14	Other	923
15	Total difference: 2013 Forecast vs. 2012 Forecast	2,706
	Consulting	
16	2013 Forecast	13,172
17	2012 Forecast	11,082
18	Difference	2,090
	Reasons:	
19	Market Development - Energy Technology and Innovation Canada	2,010
20	Other	80
21	Total difference: 2013 Forecast vs. 2012 Forecast	2,090

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	General	
1	2013 Forecast	22,190
2	2012 Forecast	21,592
3	Difference	598
	Reasons:	
4	Other	598
5	Total difference: 2013 Forecast vs. 2012 Forecast	598
	Transportation and Maintenance	
6	2013 Forecast	7,478
7	2012 Forecast	7,414
8	Difference	64
	Reasons:	
9	Volume and price	64
10	Total difference: 2013 Forecast vs. 2012 Forecast	64
	Company Used Gas	
11	2013 Forecast	2,501
12	2012 Forecast	2,473
13	Difference	28
	Reasons:	
14	Volume and price	28
15	Total difference: 2013 Forecast vs. 2012 Forecast	28
	Utility Costs	
16	2013 Forecast	4,682
17	2012 Forecast	4,562
18	Difference	120
	Reasons:	
19	Increased utility costs	120
20	Total difference: 2013 Forecast vs. 2012 Forecast	120

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Communications	
1	2013 Forecast	6,380
2	2012 Forecast	6,243
3	Difference	137
	Reasons:	
4	Other	137
5	Total difference: 2013 Forecast vs. 2012 Forecast	137
	Demand Side Management Programs	
6	2013 Forecast	24,232
7	2012 Forecast	23,605
8	Difference	627
	Reasons:	
9	DSM program costs	627
10	Total difference: 2013 Forecast vs. 2012 Forecast	627
	Advertising	
11	2013 Forecast	2,386
12	2012 Forecast	2,288
13	Difference	98
	Reasons:	
14	Other	98
15	Total difference: 2013 Forecast vs. 2012 Forecast	98
	Insurance	
16	2013 Forecast	9,056
17	2012 Forecast	8,605
18	Difference	451
	Reasons:	
19	Higher insurance premiums	451
20	Total difference: 2013 Forecast vs. 2012 Forecast	451

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Donations	
1	2013 Forecast	788
2	2012 Forecast	775
3	Difference	13
	Reasons:	
4	Other	13
5	Total difference: 2013 Forecast vs. 2012 Forecast	13
	Financial	
6	2013 Forecast	1,871
7	2012 Forecast	1,860
8	Difference	11
	Reasons:	
9	Other	11
10	Total difference: 2013 Forecast vs. 2012 Forecast	11
	Lease	
11	2013 Forecast	4,191
12	2012 Forecast	4,151
13	Difference	40
	Reasons:	
14	Other	40
15	Total difference: 2013 Forecast vs. 2012 Forecast	40
	Cost Recovery from Third Parties	
16	2013 Forecast	(2,549)
17	2012 Forecast	(2,883)
18	Difference	334
	Reasons:	
19	Other	334
20	Total difference: 2013 Forecast vs. 2012 Forecast	334

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Computers	
1	2013 Forecast	6,465
2	2012 Forecast	6,158
3	Difference	307
	Reasons:	
4	Other	307
5	Total difference: 2013 Forecast vs. 2012 Forecast	307
	Regulatory Hearing & OEB Cost Assessment	
6	2013 Forecast	4,300
7	2012 Forecast	5,200
8	Difference	(900)
	Reasons:	
9	Rebasing	(900)
10	Total difference: 2013 Forecast vs. 2012 Forecast	(900)
	Outbound Affiliate Services	
11	2013 Forecast	(13,706)
12	2012 Forecast	(13,667)
13	Difference	(39)
	Reasons:	
14	Other	(39)
15	Total difference: 2013 Forecast vs. 2012 Forecast	(39)
	Inbound Affiliate Services	
16	2013 Forecast	11,888
17	2012 Forecast	11,494
18	Difference	394
	Reasons:	
19	Other	394
20	Total difference: 2013 Forecast vs. 2012 Forecast	394

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	($000's)
	Bad Debt	
1	2013 Forecast	6,600
2	2012 Forecast	6,600
3	Difference	-
4	Total difference: 2013 Forecast vs. 2012 Forecast	-
	Other	
5	2013 Forecast	139
6	2012 Forecast	141
7	Difference	(2)
	Reasons:	
8	Other	(2)
9	Total difference: 2013 Forecast vs. 2012 Forecast	(2)

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	198,732
2	Adjustments: vehicle depreciation through clearing	2,265
3	Provision for depreciation amortization and depletion	196,467

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	1,321		63
2	Intangible plant - Other	6,356		122
3		7,677		185
	Local Storage Plant			
4	Structures and improvements	3,299	2.85%	94
5	Gas holders - storage	4,574	2.54%	116
6	Gas holders - equipment	13,250	3.54%	469
7	Regulatory Overheads	1,656	30	55
8		22,779		734
	Storage:			
9	Land rights	32,062	2.10%	673
10	Structures and improvements	47,792	2.50%	1,195
11	Wells and lines	90,073	2.48%	2,234
12	Compressor equipment	235,882	2.68%	6,322
13	Measuring & regulating equipment	46,275	3.11%	1,439
14	Other Storage Equipment	2,302	20.00%	460
15	Regulatory Overheads	14,664	35	419
16		469,050		12,742
	Transmission:			
17	Land rights	37,846	1.76%	666
18	Structures and improvements	54,602	2.03%	1,108
19	Mains	1,078,915	1.98%	21,362
20	Compressor equipment	337,120	3.23%	10,889
21	Measuring & regulating equipment	166,532	2.60%	4,330
22	Regulatory Overheads	44,785	40	1,120
23		1,719,800		39,475
	Distribution - Southern Operations:			
24	Land rights	7,571	1.65%	125
25	Structures and improvements	129,114	2.22%	2,866
26	Services - metallic	113,773	2.81%	3,197
27	Services - plastic	783,833	2.51%	19,674
28	Regulators	68,701	5.00%	3,439
29	Regulator and meter installations	70,003	2.80%	1,956
30	Mains - metallic	414,764	2.83%	11,738
31	Mains - plastic	531,747	2.31%	12,284
32	Measuring & regulating equipment	38,524	3.66%	1,410
33	Meters	226,902	3.82%	8,668
34	Regulatory Overheads	72,124	35	2,061
35		2,457,056		67,418

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	9,443	1.71%	161
2	Structures & improvements	62,145	2.41%	1,498
3	Services - metallic	96,441	3.22%	3,106
4	Services - plastic	374,732	2.60%	9,743
5	Regulators	27,294	5.00%	1,365
6	Regulator and meter installations	29,845	2.92%	871
7	Mains - metallic	379,283	3.02%	11,454
8	Mains - plastic	208,318	2.38%	4,958
9	Compressor equipment	-		-
10	Measuring & regulating equipment	110,387	3.77%	4,162
11	Meters	65,744	4.03%	2,649
12	Regulatory Overheads	32,523	35	929
13		1,396,155		40,896
	General:			
14	Structures and improvements	44,184	1.92%	848
15	Office furniture and equipment	6,405	6.67%	427
16	Office equipment - computers	101,827	25.00%	25,457
17	Transportation equipment	41,741	13.27%	5,539
18	Heavy work equipment	18,649	6.92%	1,291
19	Tools and other equipment	29,694	6.67%	1,981
20	Communications equipment	15,145	6.67%	1,010
21	Communications structures	225	6.67%	15
22	Regulatory Overheads	7,143	10	714
23		265,013		37,282
24	Contributions in aid of construction			
25	Sub-total	6,337,530		198,732
26	Total provision for depreciation and amortization	6,337,530		198,732
27	Depreciation through clearing			2,265
28		6,337,530		196,467

Note:

(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000's)	Forecast 2013	
	Determination of Taxable Income		
1	Utility income before interest and income taxes [1]	245,810	/u
	Adjustments required to arrive at taxable utility income:		
2	Interest expense	(145,358)	
3	Utility permanent differences	4,693	
4		105,145	/u
	Utility timing differences		
5	Capital Cost Allowance	(185,690)	
6	Depreciation [2]	196,467	
7	Depreciation through clearing [2]	2,265	
8	Other	(32,921)	
9	Gas Cost Deferral and Other (current)	-	
10		(19,879)	
11	Taxable income	85,266	/u
	Calculation of Utility Income Taxes		
12	Income taxes (line 11 * line 18)	21,743	/u
13	Deferred tax on Gas Cost Deferrals	-	
14	Deferred tax drawdown	(15,169)	
15	Total taxes	6,574	/u
	Tax Rates		
16	Federal tax	15.00%	
17	Provincial tax	10.50%	
18	Total tax rate	25.50%	

Notes:
(1) Exhibit F3, Tab 2, Schedule 1.
(2) Exhibit D3, Tab 4, Schedule 1.

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Calendar Year Ending December 31, 2013

Line No.	Class	Particulars ($000's)	Average CCA Balance (a)	Rate (%) (b)	Provision (c)
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4.0%	50,399
2	1	Non-residential building acquired after March 19, 2007	83,527	6.0%	5,012
3	2	Mains acquired before 1988	147,495	6.0%	8,850
4	3	Buildings acquired before 1988	4,279	5.0%	214
5	6	Other buildings	173	10.0%	17
6	7	Compression equipment acquired after February 22, 2005	165,697	15.0%	24,855
7	8	Compression assets, office furniture, equipment	79,640	20.0%	15,928
8	10	Transportation, computer equipment	18,611	30.0%	5,583
9	12	Computer software, small tools	7,701	100.0%	7,701
10	13	Leasehold improvements	332	N/A (1)	113
11	17	Roads, sidewalk, parking lot or storage areas	946	8.0%	76
12	38	Heavy work equipment	6,878	30.0%	2,063
13	41	Storage assets	8,019	25.0%	2,005
14	45	Computer hardware acquired after March 22, 2004 and before March 19, 2007	246	45.0%	111
15	49	Transmission pipelines acquired after February 22, 2005	204,628	8.0%	16,370
16	50	Computer hardware acquired after March 18, 2007	22,934	55.0%	12,614
17	51	Distribution pipelines acquired after March 18, 2007	562,998	6.0%	33,780
18	52	Computer hardware acquired after January 27, 2009 and before February 2011	0	100.0%	0
19		Total	2,574,078		185,690

Note:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2013

Line No.	Particulars	FTE (a)	($000's) Total Salaries [1] (b)	Total Variable Pay [2] (c)	Total Benefit [3] (d)	
1	Management	1,038	98,711	16,054	39,345	/u
2	Analyst	274	17,928	1,004	9,015	/u
3	Unionized	914	67,244	1,659	29,657	/u
4	Non-Unionized	91	4,608	313	2,794	/u
5	Total	2,317	188,491	19,030	80,811	/u

Line No.	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit	
6	Management	148,475	95,102	15,467	37,906	/u
7	Analyst	101,874	65,336	3,660	32,878	/u
8	Unionized	107,866	73,593	1,816	32,457	/u
9	Non-Unionized	84,846	50,679	3,437	30,730	/u
10	Average	124,440	81,351	8,213	34,876	/u

Note:
(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
FTE Report by Administrator
for the years ending December 31

Line No.	Particulars	Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)	
1	Executive	8	8	8	8	/u
2	Business Development	146	137	150	152	/u
3	Operations	1,313	1,297	1,357	1,358	/u
4	Regulatory	48	57	61	61	/u
5	Information Technology	170	171	177	177	/u
6	Corporate Services	477	498	513	515	/u
7	Human Resources	49	51	53	46	/u
8	Total	2,211	2,219	2,319	2,317	/u
9	Vacancy assumption in forecast			(69)	(69)	
10	Forecasted FTE			2,250	2,248	
	Variance explanation:					
	Role additions:					
11	Business Development			3	2	/u
12	Operations		7	2	1	/u
13	Regulatory		3			/u
14	Information Technology		3	2		/u
15	Corporate Services		8	1	2	/u
16	DSM Roles		3	1		/u
17	Human Resources (temp staffing)		2	1	(7)	/u
	Role reductions:					
18	Operations			(4)		/u
19	Corporate Services		(15)			/u
20	Additional vacancies in 2011 vs. 2010		(3)			/u
21	Seasonal in Operations laid off at end of 2011			25		/u
22	Total Variance		8	31	(2)	/u

UNION GAS LIMITED
Comparison of Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Forecast 2012	Actual 2011	Difference	
		(a)	(b)	(c)	
1	Cost of gas	721,228	755,941	(34,713)	/u
2	Operating and maintenance	383,774	371,731	12,043	/u
3	Depreciation	204,145	195,477	8,668	/u
4	Other financing	362	343	19	/u
5	Property taxes	62,916	60,700	2,216	/u
6	Other expense	-	(709)	709	/u
7	Income taxes	18,560	33,119	(14,560)	/u
8	Cost of service excluding return	1,390,985	1,416,602	(25,617)	/u

UNION GAS LIMITED
Gas Purchase Expense
Year Ending December 31, 2012

Line No.	Particulars	Volume (TJ) (a)	Cost ($000's) (b)	% of Total Volume (c)
Section A				
	Supply Transportation			
1	Western Canadian Firm	94,568	193,765	
2	U.S. Firm	43,790	22,016	
3	Adjustments	-	(232)	
4	Total Supply Transport	138,359	215,550	
	Supply Commodity			
5	Western Canadian Firm	75,637	320,860	48%
6	U.S. Firm	43,790	209,371	28%
7	Ontario Delivered Supplies	18,237	93,027	12%
8	Northern Bundled T-Service	18,931	-	12%
9	Adjustments	-	-	0%
10	Other	-	-	0%
11	Total Supply Commodity	156,595	623,257	100%
	Storage			
12	STS and Related Services		21,752	
13	Total Supply at Cost		860,558	
Section B				
	Storage Inventory Change			
14	LNG	-	-	
15	Other Company Owned	1,489	7,996	
16	3rd Party	-	-	
17	Total Gas (to) from Storage	1,489	7,996	
Section C				
18	Total Third Party Storage		398	
19	Total Section A, B, & C		868,952	

UNION GAS LIMITED
Gas Purchase Expense
Year Ending December 31, 2012

Line No.	Particulars	Volume (TJ)	Cost ($000's)	
		(a)	(b)	
	Gas Supply			
1	Total Supply at Cost	156,595	860,956	
2	Deferred Cost		(91,626)	
3	Total Gas Supply	156,595	769,330	
4	Gas (to) from Storage	1,489	7,996	
5	Winter Peaking Service		-	
6	Other Transportation		972	
7	Company Use Adj.		(4,098)	
8	Linepack		(5)	
9	Deferral Adjustment		(44,422)	
10	UFG Adjustment		(8,088)	/u
11	Accounting Adjustment		-	
12	Total Cost of Gas	158,084	721,684	/u
13	Less: Unregulated costs		(2,176)	/u
14			719,508	/u
15	Add: Costs related to short-term storage revenue		1,720	/u
16	Total Utility Cost of Gas		721,228	/u

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2012

Line No.	Particulars	Volume (a)	Weighting (b)	Volume Weighted (c)	
	Determination of Forecast UFG volume for 2012				
	3 year average of actual UFG ($10^3 m^3$):				
1	2011	35,668	50%	17,834	/u
2	2010	67,283	33%	22,203	/u
3	2009	201,845	17%	34,314	/u
4	Average actual UFG volume			74,351	/u
	3 year average of actual throughput ($10^6 m^3$):				
5	2011	33,824	50%	16,912	/u
6	2010	35,090	33%	11,580	/u
7	2009	31,677	17%	5,385	/u
8	Average actual UFG throughput			33,877	/u
9	UFG ratio for 2012 (line 4 / line 8 / 1,000)			0.219%	/u
10	2012 total forecast throughput ($10^6 m^3$)			34,791	
11	Estimated UFG volume for 2012 ($10^3 m^3$) (1)			76,356	/u
12	Estimated UFG for 2012 ($000's) (2)			15,470	/u
13	Unregulated Allocation - Short-Term ($000's)		2.471%	(382)	/u
14	Unregulated Allocation - Long-Term ($000's)		7.001%	(1,083)	/u

Note:
(1) Line 9 * line 10 * 1,000.
(2) Calculated using EB-2010-0359 reference price of $202.61/10^3 m^3.

UNION GAS LIMITED
Operating and Maintenance Expense by Administrator
Calender Year Ending December 31

Line No.	Particulars ($000's)	Forecast 2012	
1	Affiliate Services (Inbound & Outbound)	(2,173)	
2	Audit Services	476	
3	Bad Debt Expense	6,600	
4	Business Development, Storage & Transmission	16,010	
5	Corporate Adjustments	5,641	/u
6	Distribution Operations	121,685	
7	Employee & Labour Relations	106,546	/u
8	Energy Conservation	30,954	
9	Engineering, Construction & STO	45,135	
10	Environment, Health & Governance	862	
11	Executive	3,201	
12	Finance	10,469	
13	Government Affairs / Relations	975	
14	Insurance	9,013	
15	IT - Information Systems	11,807	
16	IT - Information Technology Infrastructure	14,564	
17	IT - Other	2,726	
18	Legal	1,384	
19	Marketing & Customer Care	59,509	
20	Procurement / Supply Chain	2,016	
21	Project Systems & Controls	202	
22	Regulatory, Municipal Relations and Public Affairs	18,014	
23	Tax	1,171	
24	Total	466,787	/u
25	Capitalization	(69,808)	/u
26	Non-Utility Allocation	(13,205)	/u
27	Total Net Utility Operating and Maintenance Expense	383,774	/u
28	Excess Utility Cross-Charge	(2,261)	
29	Total Net Utility O&M Less Cross-Charge	381,513	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars ($000's)	Forecast 2012	Actual 2011	Difference	%	
		(a)	(b)	(c)	(d)	
1	Salaries/Wages	187,950	191,837	(3,887)	(2.03%)	/u
2	Benefits	82,161	81,179	982	1.21%	/u
3	Materials	9,242	10,701	(1,459)	(13.63%)	/u
4	Employee Expenses/Training	14,110	13,514	596	4.41%	/u
5	Contract Services	63,670	63,608	62	0.10%	/u
6	Consulting	11,082	7,713	3,369	43.68%	/u
7	General	21,592	22,262	(670)	(3.01%)	/u
8	Transportation and Maintenance	9,375	9,012	363	4.03%	/u
9	Company Used Gas	2,473	2,401	72	3.00%	/u
10	Utility Costs	4,562	4,069	493	12.12%	/u
11	Communications	6,243	6,394	(151)	(2.36%)	/u
12	Demand Side Management Programs	23,605	17,925	5,680	31.69%	/u
13	Advertising	2,288	2,376	(88)	(3.70%)	/u
14	Insurance	8,605	8,101	504	6.22%	/u
15	Donations	775	632	143	22.63%	/u
16	Financial	1,860	1,682	178	10.58%	/u
17	Lease	4,151	4,092	59	1.44%	/u
18	Cost Recovery from Third Parties	(2,883)	(5,869)	2,986	(50.88%)	/u
19	Computers	6,158	5,287	871	16.47%	/u
20	Regulatory Hearing & OEB Cost Assessment	5,200	3,306	1,894	57.29%	/u
21	Outbound Affiliate Services	(13,667)	(11,697)	(1,970)	16.84%	/u
22	Inbound Affiliate Services	11,494	8,956	2,538	28.34%	/u
23	Bad Debt	6,600	4,455	2,145	48.15%	/u
24	Other	141	206	(65)	(31.55%)	/u
25	Total Gross Operating and Maintenance Expense	466,787	452,142	14,645	3.24%	/u
26	Indirect Capitalization	(50,789)	(52,220)	1,431	(2.74%)	/u
27	Direct Capitalization	(19,019)	(15,149)	(3,870)	25.55%	/u
28	Total Utility Operating and Maintenance Expense	396,979	384,773	12,206	3.17%	/u
29	Non-Utility Allocations	(13,205)	(13,042)	(163)	1.25%	/u
30	Total Net Utility Operating and Maintenance Expense	383,774	371,731	12,043	3.24%	/u
31	Excess Utility Cross-Charge	(2,261)	(2,261)	-	0.00%	
32	Total Net Utility O&M Less Cross-Charge	381,513	369,470	12,043	3.26%	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Salaries / Wages		
1	2012 Forecast	187,950	
2	2011 Actual	191,837	/u
3	Difference	(3,887)	/u
	Reasons:		
4	Merit increase	5,549	/u
5	STIP/LTIP	(6,885)	/u
6	Market Development - Energy Technology and Innovation Canada	96	/u
7	2011 Severance	(1,200)	/u
8	2011 Overtime	(1,100)	/u
9	Goderich work	(300)	/u
10	Other	(47)	/u
11	Total difference: 2012 Forecast vs. 2011 Actual	(3,887)	/u
	Benefits		
12	2012 Forecast	82,161	/u
13	2011 Actual	81,179	/u
14	Difference	982	/u
	Reasons:		
15	Decreased non pension benefit costs	(714)	/u
16	Increased pension benefit costs	1,696	/u
17	Total difference: 2012 Forecast vs. 2011 Actual	982	/u
	Materials		
18	2012 Forecast	9,242	
19	2011 Actual	10,701	/u
20	Difference	(1,459)	/u
	Reasons:		
21	2011 Write off of obsolete inventory	(1,200)	/u
22	Other	(259)	/u
23	Total difference: 2012 Forecast vs. 2011 Actual	(1,459)	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Employee Expenses / Training		
1	2012 Forecast	14,110	
2	2011 Actual	13,514	/u
3	Difference	596	/u
	Reasons:		
4	Travel	68	/u
5	Meals, entertainment, accomodation	178	/u
6	Training and education	947	/u
7	Moving, relocation	(507)	/u
8	Other	(90)	/u
9	Total difference: 2012 Forecast vs. 2011 Actual	596	/u
	Contract Services		
10	2012 Forecast	63,670	
11	2011 Actual	63,608	/u
12	Difference	62	/u
	Reasons:		
13	Distribution integrity - cross bore	1,100	/u
14	Pipeline integrity	600	/u
15	2011 Dawn STO costs offset in recovery	(1,170)	/u
16	Other	(468)	/u
17	Total difference: 2012 Forecast vs. 2011 Actual	62	/u
	Consulting		
18	2012 Forecast	11,082	
19	2011 Actual	7,713	/u
20	Difference	3,369	/u
	Reasons:		
21	Market Development - Energy Technology and Innovation Canada	2,303	
22	Other	1,066	/u
23	Total difference: 2012 Forecast vs. 2011 Actual	3,369	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	General		
1	2012 Forecast	21,592	
2	2011 Actual	22,262	/u
3	Difference	(670)	/u
	Reasons:		
4	Other	(670)	/u
5	Total difference: 2012 Forecast vs. 2011 Actual	(670)	/u
	Transportation and Maintenance		
6	2012 Forecast	9,375	/u
7	2011 Actual	9,012	/u
8	Difference	363	/u
	Reasons:		
9	Volume and price	363	/u
10	Total difference: 2012 Forecast vs. 2011 Actual	363	/u
	Company Used Gas		
11	2012 Forecast	2,473	
12	2011 Actual	2,401	/u
13	Difference	72	/u
	Reasons:		
14	Volume and price	72	/u
15	Total difference: 2012 Forecast vs. 2011 Actual	72	/u
	Utility Costs		
16	2012 Forecast	4,562	
17	2011 Actual	4,069	/u
18	Difference	493	/u
	Reasons:		
19	Increased utility costs	493	/u
20	Total difference: 2012 Forecast vs. 2011 Actual	493	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Communications		
1	2012 Forecast	6,243	
2	2011 Actual	6,394	/u
3	Difference	(151)	/u
	Reasons:		
4	Other	(151)	/u
5	Total difference: 2012 Forecast vs. 2011 Actual	(151)	/u
	Demand Side Management Programs		
6	2012 Forecast	23,605	
7	2011 Actual	17,925	/u
8	Difference	5,680	/u
	Reasons:		
9	DSM program costs	5,680	/u
10	Total difference: 2012 Forecast vs. 2011 Actual	5,680	/u
	Advertising		
11	2012 Forecast	2,288	
12	2011 Actual	2,376	/u
13	Difference	(88)	/u
	Reasons:		
14	Other	(88)	/u
15	Total difference: 2012 Forecast vs. 2011 Actual	(88)	/u
	Insurance		
16	2012 Forecast	8,605	
17	2011 Actual	8,101	/u
18	Difference	504	/u
	Reasons:		
19	Higher insurance premiums	504	/u
20	Total difference: 2012 Forecast vs. 2011 Actual	504	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Donations		
1	2012 Forecast	775	
2	2011 Actual	632	/u
3	Difference	143	/u
	Reasons:		
4	Other	143	/u
5	Total difference: 2012 Forecast vs. 2011 Actual	143	/u
	Financial		
6	2012 Forecast	1,860	
7	2011 Actual	1,682	/u
8	Difference	178	/u
	Reasons:		
9	Other	178	/u
10	Total difference: 2012 Forecast vs. 2011 Actual	178	/u
	Lease		
11	2012 Forecast	4,151	
12	2011 Actual	4,092	/u
13	Difference	59	/u
	Reasons:		
14	Other	59	/u
15	Total difference: 2012 Forecast vs. 2011 Actual	59	/u
	Cost Recovery from Third Parties		
16	2012 Forecast	(2,883)	
17	2011 Actual	(5,869)	/u
18	Difference	2,986	/u
	Reasons:		
19	2011 Dawn STO - Bright, Lobo, Sandwich, Other	1,170	/u
20	2011 Goderich tornado	345	/u
21	2011 Streamline	200	/u
22	Other	1,271	/u
23	Total difference: 2012 Forecast vs. 2011 Actual	2,986	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Computers		
1	2012 Forecast	6,158	
2	2011 Actual	5,287	/u
3	Difference	871	/u
	Reasons:		
4	Software maintenance/licenses	871	/u
5	Total difference: 2012 Forecast vs. 2011 Actual	871	/u
	Regulatory Hearing & OEB Cost Assessment		
6	2012 Forecast	5,200	
7	2011 Actual	3,306	/u
8	Difference	1,894	/u
	Reasons:		
9	Rebasing	1,894	/u
10	Total difference: 2012 Forecast vs. 2011 Actual	1,894	/u
	Outbound Affiliate Services		
11	2012 Forecast	(13,667)	
12	2011 Actual	(11,697)	/u
13	Difference	(1,970)	/u
	Reasons:		
14	Other	(1,970)	/u
15	Total difference: 2012 Forecast vs. 2011 Actual	(1,970)	/u
	Inbound Affiliate Services		
16	2012 Forecast	11,494	
17	2011 Actual	8,956	/u
18	Difference	2,538	/u
	Reasons:		
19	Other	2,538	/u
20	Total difference: 2012 Forecast vs. 2011 Actual	2,538	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2012 Forecast vs. 2011 Actual

Line No.	Particulars	($000's)	
	Bad Debt		
1	2012 Forecast	6,600	
2	2011 Actual	4,455	/u
3	Difference	2,145	/u
	Reasons:		
4	WACOG and bad debt experience	2,145	/u
5	Total difference: 2012 Forecast vs. 2011 Actual	2,145	/u
	Other		
6	2012 Forecast	141	
7	2011 Actual	206	/u
8	Difference	(65)	/u
	Reasons:		
9	Other	(65)	/u
10	Total difference: 2012 Forecast vs. 2011 Actual	(65)	/u

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	206,090
2	Adjustments: vehicle depreciation through clearing	1,945
3	Provision for depreciation amortization and depletion	204,145

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	1,321		63
2	Intangible plant - Other	6,363		122
3		7,684		185
	Local Storage Plant			
4	Structures and improvements	3,044	3.30%	100
5	Gas holders - storage	4,574	2.68%	123
6	Gas holders - equipment	11,766	3.68%	433
7	Regulatory Overheads	1,121	30	37
8		20,505		693
	Storage:			
9	Land rights	32,062	2.23%	715
10	Structures and improvements	52,005	2.34%	1,217
11	Wells and lines	89,144	2.66%	2,371
12	Compressor equipment	238,852	3.19%	7,620
13	Measuring & regulating equipment	48,498	4.30%	2,085
14	Other Storage Equipment	2,302	20.00%	460
15	Regulatory Overheads	12,128	35	347
16		474,991		14,815
	Transmission:			
17	Land rights	37,770	2.00%	755
18	Structures and improvements	54,631	2.66%	1,453
19	Mains	1,058,173	2.37%	25,079
20	Compressor equipment	338,743	3.52%	11,924
21	Measuring & regulating equipment	155,040	3.61%	5,597
22	Regulatory Overheads	27,467	40	687
23		1,671,824		45,495
	Distribution - Southern Operations:			
24	Land rights	7,372	1.67%	123
25	Structures and improvements	110,184	2.91%	3,206
26	Services - metallic	111,373	3.69%	4,110
27	Services - plastic	764,398	3.18%	24,308
28	Regulators	75,389	3.30%	2,490
29	Regulator and meter installations	69,447	3.51%	2,435
30	Mains - metallic	410,512	2.54%	10,427
31	Mains - plastic	517,431	2.34%	12,108
32	Measuring & regulating equipment	34,271	4.64%	1,590
33	Meters	212,931	3.70%	7,878
34	Regulatory Overheads	54,047	35	1,544
35		2,367,355		70,219

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	9,321	1.68%	157
2	Structures & improvements	61,773	3.13%	1,933
3	Services - metallic	95,016	3.58%	3,401
4	Services - plastic	364,101	3.19%	11,615
5	Regulators	29,710	3.34%	992
6	Regulator and meter installations	29,613	3.50%	1,036
7	Mains - metallic	359,481	2.52%	9,059
8	Mains - plastic	204,743	2.35%	4,811
9	Compressor equipment	-	3.34%	-
10	Measuring & regulating equipment	107,756	4.63%	4,989
11	Meters	60,819	3.67%	2,232
12	Regulatory Overheads	22,346	35	638
13		1,344,679		40,863
	General:			
14	Structures and improvements	43,834	2.13%	934
15	Office furniture and equipment	6,829	6.67%	455
16	Office equipment - computers	95,184	25.00%	23,796
17	Transportation equipment	41,477	10.07%	4,177
18	Transportation equipment - aircraft			-
19	Heavy work equipment	17,465	4.55%	795
20	Tools and other equipment	29,300	6.67%	1,954
21	Communications equipment	14,226	6.67%	949
22	Communications structures	1,471	4.88%	72
23	Regulatory Overheads	6,879	10	688
24		256,665		33,820
25	Contributions in aid of construction	-		-
26	Sub-total	6,143,703		206,090
27	Total provision for depreciation and amortization	6,143,703		206,090
28	Depreciation through clearing			1,945
29		6,143,703		204,145

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000's)	Forecast 2012	
	Determination of Taxable Income		
1	Utility income before interest and income taxes (1)	278,493	/u
	Adjustments required to arrive at taxable utility income:		
2	Interest expense	(145,359)	
3	Utility permanent differences	4,524	
4		137,658	/u
	Utility timing differences		
5	Capital Cost Allowance	(181,732)	
6	Depreciation (2)	204,145	
7	Depreciation through clearing (2)	1,945	
8	Other	(34,799)	
9	Gas Cost Deferral and Other (current)	(30,197)	/u
10		(40,638)	/u
11	Taxable income	97,020	/u
	Calculation of Utility Income Taxes		
12	Income taxes (line 11 * line 18)	25,468	/u
13	Deferred tax on Gas Cost Deferrals	7,927	/u
14	Deferred tax drawdown	(14,835)	
15	Total taxes	18,560	/u
	Tax Rates		
16	Federal tax	15.00%	
17	Provincial tax	11.25%	
18	Total tax rate	26.25%	

Notes:
(1) Exhibit F4, Tab 2, Schedule 1.
(2) Exhibit D4, Tab 4, Schedule 1.

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)		Average CCA Balance	Rate (%)	Provision
			(a)	(b)	(c)
	Class				
1	1	Buildings, structures and improvements, services, meters, mains	1,311,506	4.0%	52,460
2	1	Non-residential building acquired after March 19, 2007	65,112	6.0%	3,907
3	2	Mains acquired before 1988	156,910	6.0%	9,415
4	3	Buildings acquired before 1988	4,504	5.0%	225
5	6	Other buildings	192	10.0%	19
6	8	Compression assets, office furniture, equipment	72,292	20.0%	14,458
7	7	Compression equipment acquired after February 22, 2005	186,496	15.0%	27,974
8	10	Transportation, computer equipment	18,544	30.0%	5,563
9	12	Computer software, small tools	11,758	100.0%	11,758
10	13	Leasehold improvements	446	N/A (1)	113
11	17	Roads, sidewalk, parking lot or storage areas	1,028	8.0%	82
12	38	Heavy work equipment	6,946	30.0%	2,084
13	41	Storage assets	8,769	25.0%	2,192
14	45	Computer hardware acquired after March 22, 2004 and before March 19, 200	448	45.0%	202
15	49	Transmission pipelines acquired after February 22, 2005	195,066	8.0%	15,605
16	50	Computer hardware acquired after March 18, 2007	14,977	55.0%	8,237
17	51	Distribution pipelines acquired after March 18, 2007	457,271	6.0%	27,436
18	52	Computer hardware acquired after January 27, 2009 and before February 201	0	100.0%	0
19	Total		2,512,265		181,732

Note:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2012

Line No.	Particulars	FTE (a)	($000's) Total Salaries (1) (b)	Total Variable Pay (2) (c)	Total Benefit (3) (d)	
1	Management	1,037	95,543	15,451	38,085	/u
2	Analyst	277	17,306	971	9,022	/u
3	Unionized	914	65,134	1,604	29,384	/u
4	Non-Unionized	91	4,456	302	2,792	/u
5	Total	2,319	182,439	18,328	79,283	/u

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit	
6	Management	143,709	92,099	14,894	36,716	/u
7	Analyst	98,690	62,566	3,510	32,614	/u
8	Unionized	105,156	71,255	1,755	32,146	/u
9	Non-Unionized	83,039	49,013	3,321	30,705	/u
10	Average	120,763	78,671	7,903	34,189	/u

Note:
(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
Comparison of Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Actual 2011	Actual 2010	Difference	
		(a)	(b)	(c)	
1	Cost of gas	755,941	795,549	(39,608)	/u
2	Operating and maintenance	371,731	351,634	20,097	/u
3	Depreciation	195,477	190,176	5,301	/u
4	Other financing	343	621	(278)	/u
5	Property and capital taxes	60,700	65,131	(4,431)	/u
6	Other expense	(709)	500	(1,209)	/u
7	Income taxes	33,119	30,214	2,906	/u
8	Cost of service excluding return	1,416,602	1,433,825	(17,223)	/u

UNION GAS LIMITED
Gas Purchase Expense
Year Ending December 31, 2011

Line No.	Particulars	Volume (TJ)	Cost ($000's)	% of Total Volume	
		(a)	(b)	(c)	
Section A					
	Supply Transportation				
1	Western Canadian Firm	103,586	200,116		/u
2	U.S. Firm	51,922	22,294		/u
3	Adjustments	-	2,637		/u
4	Total Supply Transport	155,508	225,047		/u
	Supply Commodity				
5	Western Canadian Firm	88,992	296,935	52%	/u
6	U.S. Firm	48,431	181,476	29%	/u
7	Ontario Delivered Supplies	14,132	58,236	8%	/u
8	Northern Bundled T-Service	18,085	-	11%	/u
9	Adjustments	-	70	0%	/u
10	Other	-	-	0%	
11	Total Supply Commodity	169,640	536,717	100%	/u
	Storage				
12	STS and Related Services		14,998		/u
13	Total Supply at Cost		776,762		/u
Section B					
	Storage Inventory Change				
14	LNG	-	-		
15	Other Company Owned	(14,113)	(83,812)		/u
16	3rd Party	-	-		
17	Total Gas (to) from Storage	(14,113)	(83,812)		
Section C					
18	Total Third Party Storage		290		/u
19	Total Section A, B, & C		693,240		/u

UNION GAS LIMITED
Gas Purchase Expense
Year Ending December 31, 2011

Line No.	Particulars	Volume (TJ) (a)	Cost ($000's) (b)	% of Total Volume (c)	
	Gas Supply				
1	Total Supply at Cost	169,640	777,052		/u
2	Deferred Costs		125,507		/u
3	Total Gas Supply	169,640	902,559		/u
4	Gas (to) from Storage	(14,113)	(83,812)		/u
5	Winter Peaking Service		2,437		/u
6	Other Transportation		972		
7	Company Use Adj.		(8,610)		/u
8	Linepack		-		
9	Deferral Adjustment		(66,948)		/u
10	UFG Adjustment		8,028		/u
11	Accounting Adjustment		640		/u
12	Total Cost of Gas	155,527	755,265		/u
13	Unregulated costs		215		/u
14			755,480		/u
15	Add: Costs related to short-term storage revenue		803		/u
16	Total Utility Cost of Gas		756,283		/u

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2011

Line No.	Particulars	Volume (a)	Weighting (b)	Volume Weighted (c)	
	Determination of Forecast UFG volume for 2011				
	3 year average of actual UFG (10^3m^3):				
1	2009	201,845	50%	100,923	
2	2008	143,880	33%	47,480	
3	2007	203,713	17%	34,631	
4	Average actual UFG volume			183,034	
	3 year average of actual throughput (10^6m^3):				
5	2009	31,677	50%	15,839	
6	2008	34,978	33%	11,543	
7	2007	33,446	17%	5,686	
8	Average actual UFG throughput			33,068	
9	UFG ratio for 2011 (Line 4 / Line 8 / 1,000)			0.554%	
10	2011 total forecast throughput (10^6m^3)			33,185	
11	Estimated UFG volume for 2011 (10^3m^3) (1)			183,684	
12	Actual UFG volume for 2011 (10^3m^3)			35,668	/u
13	Actual UFG ($000's) (2)			8,041	/u

Note:
(1) Line 9 * line 10 * 1,000.
(2) Calculated using EB-2010-0359 reference price of $202.610/$10^3$ m^3 for January to March; EB-2011-0029 reference price of $222.348/$10^3$ m^3 for April to June ; EB-2011-0135 reference price of $230.804/$10^3$ m^3 for July to September ; and EB-2011-0297 reference price of $219.252/$10^3$ m^3 for October to December.

UNION GAS LIMITED
Operating and Maintenance Expense by Administrator
Calender Year Ending December 31

Line No.	Particulars ($000's)	Actual 2011	
1	Affiliate Services (Inbound & Outbound)	(2,739)	/u
2	Audit Services	301	/u
3	Bad Debt Expense	4,455	/u
4	Business Development, Storage & Transmission	14,871	/u
5	Corporate Adjustments	2,663	/u
6	Distribution Operations	121,307	/u
7	Employee & Labour Relations	114,779	/u
8	Energy Conservation	24,890	/u
9	Engineering, Construction & STO	44,762	/u
10	Environment, Health & Governance	754	/u
11	Executive	3,259	/u
12	Finance	9,919	/u
13	Government Affairs / Relations	830	/u
14	Insurance	8,315	/u
15	IT - Information Systems	11,509	/u
16	IT - Information Technology Infrastructure	14,837	/u
17	IT - Other	2,134	/u
18	Legal	1,266	/u
19	Marketing & Customer Care	56,712	/u
20	Procurement / Supply Chain	1,714	/u
21	Project Systems & Controls	187	/u
22	Regulatory, Municipal Relations and Public Affairs	14,242	/u
23	Tax	1,175	/u
24	Total	452,142	/u
25	Capitalization	(67,369)	/u
26	Non-Utility Allocation	(13,042)	/u
27	Total Net Utility Operating and Maintenance Expense	371,731	/u
28	Excess Utility Cross-Charge	(2,261)	
29	Total Net Utility O&M Less Cross-Charge	369,470	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars ($000's)	Actual 2011	Actual 2010	Difference	%	
		(a)	(b)	(c)	(d)	
1	Salaries/Wages	191,837	183,249	8,588	4.69%	/u
2	Benefits	81,179	70,861	10,318	14.56%	/u
3	Materials	10,701	9,631	1,070	11.11%	/u
4	Employee Expenses/Training	13,514	11,783	1,731	14.69%	/u
5	Contract Services	63,608	57,335	6,273	10.94%	/u
6	Consulting	7,713	7,506	207	2.76%	/u
7	General	22,262	21,211	1,051	4.96%	/u
8	Transportation and Maintenance	9,012	7,892	1,120	14.19%	/u
9	Company Used Gas	2,401	2,451	(50)	(2.05%)	/u
10	Utility Costs	4,069	3,704	365	9.85%	/u
11	Communications	6,394	6,780	(386)	(5.70%)	/u
12	Demand Side Management Programs	17,925	16,438	1,487	9.05%	/u
13	Advertising	2,376	1,860	516	27.71%	/u
14	Insurance	8,101	8,507	(406)	(4.77%)	/u
15	Donations	632	749	(117)	(15.63%)	/u
16	Financial	1,682	2,077	(395)	(19.02%)	/u
17	Lease	4,092	3,632	460	12.65%	/u
18	Cost Recovery from Third Parties	(5,869)	(4,641)	(1,228)	26.45%	/u
19	Computers	5,287	4,922	365	7.41%	/u
20	Regulatory Hearing & OEB Cost Assessment	3,306	3,126	180	5.76%	/u
21	Outbound Affiliate Services	(11,697)	(10,182)	(1,515)	14.88%	/u
22	Inbound Affiliate Services	8,956	9,462	(506)	(5.35%)	/u
23	Bad Debt	4,455	5,075	(620)	(12.22%)	/u
24	Other	206	249	(43)	(17.33%)	/u
25	Total Gross Operating and Maintenance Expense	452,142	423,677	28,465	6.72%	/u
26	Indirect Capitalization	(52,220)	(46,289)	(5,931)	12.81%	/u
27	Direct Capitalization	(15,149)	(13,978)	(1,171)	8.38%	/u
28	Total Utility Operating and Maintenance Expense	384,773	363,410	21,363	5.88%	/u
29	Non-Utility Allocations	(13,042)	(11,776)	(1,266)	10.75%	/u
30	Total Net Utility Operating and Maintenance Expense	371,731	351,634	20,097	5.72%	/u
31	Excess Utility Cross-Charge	(2,261)	(2,261)	-	0.00%	
32	Total Net Utility O&M Less Cross-Charge	369,470	349,373	20,097	5.75%	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Salaries / Wages		
1	2011 Actual	191,837	/u
2	2010 Actual	183,249	
3	Difference	8,588	/u
	Reasons:		
4	Incentive Accrual/Payout	2,500	/u
5	Merit Increase @ 3.0%	5,100	/u
6	Severances	1,100	/u
7	Other	(112)	/u
8	Total difference: 2011 Actual vs. 2010 Actual	8,588	/u
	Benefits		
9	2011 Actual	81,179	/u
10	2010 Actual	70,861	
11	Difference	10,318	/u
	Reasons:		
12	Higher Flex Benefit Costs	1,200	/u
13	Higher Legislated Benefit Costs	800	/u
14	WSIB Refund	(400)	/u
15	Increased Pension Costs	8,800	/u
16	Other	(82)	/u
17	Total difference: 2011 Actual vs. 2010 Actual	10,318	/u
	Materials		
18	2011 Actual	10,701	/u
19	2010 Actual	9,631	
20	Difference	1,070	/u
	Reasons:		
21	Write off of obsolete inventory	1,200	/u
22	Other	(130)	/u
23	Total difference: 2011 Actual vs. 2010 Actual	1,070	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Employee Expenses / Training		
1	2011 Actual	13,514	/u
2	2010 Actual	11,783	
3	Difference	1,731	/u
	Reasons:		
4	Relocation costs	600	/u
5	Meals and accommodation expense	465	/u
6	Mileage and travel expense	530	/u
7	Employee training expense	100	/u
8	Other	36	/u
9	Total difference: 2011 Actual vs. 2010 Actual	1,731	/u
	Contract Services		
10	2011 Actual	63,608	/u
11	2010 Actual	57,335	
12	Difference	6,273	/u
	Reasons:		
13	Pipeline integrity work	2,500	/u
14	Line locate activity higher in 2011	1,500	/u
15	STO Dawn repairs	600	/u
16	Anodes station work	500	/u
17	HR service costs	300	/u
19	Olameter costs	200	/u
19	Other	673	/u
20	Total difference: 2011 Actual vs. 2010 Actual	6,273	/u
	Consulting		
21	2011 Actual	7,713	/u
22	2010 Actual	7,506	
23	Difference	207	/u
	Reasons:		
24	Seismic testing	200	/u
25	Other	7	/u
26	Total difference: 2011 Actual vs. 2010 Actual	207	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	General		
1	2011 Actual	22,262	/u
2	2010 Actual	21,211	
3	Difference	1,051	/u
	Reasons:		
4	HST Deferral	583	/u
5	Increased postage costs in 2011	200	/u
6	Other	268	/u
7	Total difference: 2011 Actual vs. 2010 Actual	1,051	/u
	Transportation and Maintenance		
8	2011 Actual	9,012	/u
9	2010 Actual	7,892	
10	Difference	1,120	/u
	Reasons:		
11	Volume and price	1,120	/u
12	Total difference: 2011 Actual vs. 2010 Actual	1,120	/u
	Company Used Gas		
13	2011 Actual	2,401	/u
14	2010 Actual	2,451	
15	Difference	(50)	/u
	Reasons:		
16	Other	(50)	/u
17	Total difference: 2011 Actual vs. 2010 Actual	(50)	/u
	Utility Costs		
18	2011 Actual	4,069	/u
19	2010 Actual	3,704	
20	Difference	365	/u
	Reasons:		
21	Increased utility costs	365	/u
22	Total difference: 2011 Actual vs. 2010 Actual	365	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Communications		
1	2011 Actual	6,394	/u
2	2010 Actual	6,780	
3	Difference	(386)	/u
	Reasons:		
4	Reductions due to Rogers APN network	(200)	/u
5	Other	(186)	/u
6	Total difference: 2011 Actual vs. 2010 Actual	(386)	/u
	Demand Side Management Programs		
7	2011 Actual	17,925	/u
8	2010 Actual	16,438	
9	Difference	1,487	/u
	Reasons:		
10	DSM program costs	1,487	/u
11	Total difference: 2011 Actual vs. 2010 Actual	1,487	/u
	Advertising		
12	2011 Actual	2,376	/u
13	2010 Actual	1,860	
14	Difference	516	/u
	Reasons:		
15	Notice of rates proceeding	100	/u
16	Customer advertising	270	/u
17	Other	146	/u
18	Total difference: 2011 Actual vs. 2010 Actual	516	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Insurance		
1	2011 Actual	8,101	/u
2	2010 Actual	8,507	
3	Difference	(406)	/u
	Reasons:		
4	Lower Insurance premiums	(406)	/u
5	Total difference: 2011 Actual vs. 2010 Actual	(406)	/u
	Donations		
6	2011 Actual	632	/u
7	2010 Actual	749	
8	Difference	(117)	/u
	Reasons:		
9	Other	(117)	/u
10	Total difference: 2011 Actual vs. 2010 Actual	(117)	/u
	Financial		
11	2011 Actual	1,682	/u
12	2010 Actual	2,077	
13	Difference	(395)	/u
	Reasons:		
14	Other	(395)	/u
15	Total difference: 2011 Actual vs. 2010 Actual	(395)	/u
	Lease		
16	2011 Actual	4,092	/u
17	2010 Actual	3,632	
18	Difference	460	/u
	Reasons:		
19	Other	460	/u
20	Total difference: 2011 Actual vs. 2010 Actual	460	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Cost Recovery from Third Parties		
1	2011 Actual	(5,869)	/u
2	2010 Actual	(4,641)	
3	Difference	(1,228)	/u
	Reasons:		
4	Dawn STO insurance recovery	(600)	/u
5	Goderich tornado insurance recovery	(345)	/u
6	Other insurance recoveries	(283)	/u
7	Total difference: 2011 Actual vs. 2010 Actual	(1,228)	/u
	Computers		
8	2011 Actual	5,287	/u
9	2010 Actual	4,922	
10	Difference	365	/u
	Reasons:		
11	Other	365	/u
12	Total difference: 2011 Actual vs. 2010 Actual	365	/u
	Regulatory Hearing & OEB Cost Assessment		
13	2011 Actual	3,306	/u
14	2010 Actual	3,126	
15	Difference	180	/u
	Reasons:		
16	Other	180	/u
17	Total difference: 2011 Actual vs. 2010 Actual	180	/u
	Outbound Affiliate Services		
18	2011 Actual	(11,697)	/u
19	2010 Actual	(10,182)	
20	Difference	(1,515)	/u
	Reasons:		
21	Other	(1,515)	/u
22	Total difference: 2011 Actual vs. 2010 Actual	(1,515)	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Inbound Affiliate Services		
1	2011 Actual	8,956	/u
2	2010 Actual	9,462	
3	Difference	(506)	/u
	Reasons:		
4	Other	(506)	/u
5	Total difference: 2011 Actual vs. 2010 Actual	(506)	/u
	Bad Debt		
6	2011 Actual	4,455	/u
7	2010 Actual	5,075	
8	Difference	(620)	/u
	Reasons:		
9	WACOG and bad debt experience	(620)	/u
10	Total difference: 2011 Actual vs. 2010 Actual	(620)	/u
	Other		
11	2011 Actual	206	/u
12	2010 Actual	249	
13	Difference	(43)	/u
	Reasons:		
14	Other	(43)	/u
15	Total difference: 2011 Actual vs. 2010 Actual	(43)	/u

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2011

Line No.	Particulars ($000's)	(a)	
	Total provision for depreciation and		
1	amortization before adjustments (per page 3)	197,151	/u
2	Adjustments: vehicle depreciation through clearing	1,674	/u
3	Provision for depreciation amortization and depletion	195,477	/u

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2011

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision	
		(a)	(b)	(c)	
	Intangible plant:				
1	Franchises and consents	1,321		63	
2	Intangible plant - Other	6,371		122	/u
3		7,692		185	/u
	Local Storage Plant				
4	Structures and improvements	2,813	3.30%	93	/u
5	Gas holders - storage	4,574	2.68%	-	/u
6	Gas holders - equipment	9,817	3.68%	361	/u
7	Regulatory Overheads	363	30	12	/u
8		17,567		466	/u
	Storage:				
9	Land rights	32,023	2.23%	714	/u
10	Structures and improvements	56,111	2.34%	1,313	/u
11	Wells and lines	87,951	2.66%	2,339	/u
12	Compressor equipment	218,016	3.19%	6,955	/u
13	Measuring & regulating equipment	60,484	4.30%	2,601	/u
14	Other Storage Equipment	1,758	20.00%	372	/u
15	Regulatory Overheads	5,300	35	152	/u
16		461,643		14,446	/u
	Transmission:				
17	Land rights	37,791	2.00%	756	/u
18	Structures and improvements	53,903	2.66%	1,434	/u
19	Mains	1,046,190	2.37%	24,795	/u
20	Compressor equipment	306,731	3.52%	10,797	/u
21	Measuring & regulating equipment	162,972	3.61%	5,883	/u
22	Regulatory Overheads	12,124	40	303	/u
23		1,619,711		43,968	/u
	Distribution - Southern Operations:				
24	Land rights	5,552	1.67%	93	/u
25	Structures and improvements	103,801	2.91%	3,041	/u
26	Services - metallic	109,721	3.69%	4,049	/u
27	Services - plastic	748,811	3.18%	23,812	/u
28	Regulators	72,011	3.30%	2,376	/u
29	Regulator and meter installations	67,740	3.51%	2,378	/u
30	Mains - metallic	403,980	2.54%	10,261	/u
31	Mains - plastic	508,277	2.34%	11,894	/u
32	Measuring & regulating equipment	29,730	4.64%	1,379	/u
33	Meters	199,423	3.70%	7,379	/u
34	Regulatory Overheads	39,031	35	1,115	/u
35		2,288,077		67,777	/u

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2011

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision	
		(a)	(b)	(c)	
	Distribution plant - Northern & Eastern Operations:				
1	Land rights	9,075	1.68%	152	/u
2	Structures & improvements	62,322	3.13%	1,967	/u
3	Services - metallic	93,239	3.58%	3,338	/u
4	Services - plastic	359,075	3.19%	11,454	/u
5	Regulators	28,012	3.34%	936	/u
6	Regulator and meter installations	29,308	3.50%	1,026	/u
7	Mains - metallic	353,866	2.52%	8,917	/u
8	Mains - plastic	202,160	2.35%	4,751	/u
9	Compressor equipment	-	3.34%	-	/u
10	Measuring & regulating equipment	106,119	4.63%	4,913	/u
11	Meters	52,711	3.67%	1,934	/u
12	Regulatory Overheads	15,649	35	447	/u
13		1,311,536		39,835	/u
	General:				
14	Structures and improvements	41,635	2.13%	942	/u
15	Office furniture and equipment	10,470	6.67%	698	/u
16	Office equipment - computers	78,684	25.00%	19,671	/u
17	Transportation equipment	46,067	10.07%	4,639	/u
18	Heavy work equipment	15,156	4.55%	707	/u
19	Tools and other equipment	30,285	6.67%	2,019	/u
20	Communications equipment	13,184	6.67%	879	/u
21	Communications structures	2,685	4.88%	131	/u
22	Regulatory Overheads	7,880	10	788	/u
23		246,046		30,474	/u
24	Contributions in aid of construction	-		-	
25	Sub-total	5,952,271		197,151	/u
26	Total provision for depreciation and amortization	5,952,271		197,151	/u
27	Depreciation through clearing	-		1,674	/u
28		5,952,271		195,477	/u

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000's)	Actual 2011	
	Determination of Taxable Income		
1	Utility income before interest and income taxes [1]	326,904	/u
	Adjustments required to arrive at taxable utility income:		
2	Interest expense	(143,821)	/u
3	Utility permanent differences	3,941	/u
4		187,024	/u
	Utility timing differences		
5	Capital Cost Allowance	(170,080)	/u
6	Depreciation [2]	195,477	/u
7	Depreciation through clearing [2]	1,674	/u
8	Other	(43,105)	/u
9	Gas Cost Deferral and Other (current)	(21,527)	/u
10		(37,561)	/u
11	Taxable income	149,463	/u
	Calculation of Utility Income Taxes		
12	Income taxes (line 11 * line 18)	42,223	/u
13	Deferred tax on Gas Cost Deferrals	6,685	/u
14	Deferred tax drawdown	(15,789)	
15	Total taxes	33,119	/u
	Tax Rates		
16	Federal tax	16.50%	
17	Provincial tax	11.75%	
18	Total tax rate	28.25%	

Notes:
(1) Exhibit F5, Tab 2, Schedule 1.
(2) Exhibit D5, Tab 4, Schedule 1.

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Calendar Year Ending December 31, 2011

Line No.	Class	Particulars ($000's)	Average CCA Balance (a)	Rate (%) (b)	Provision (c)	
1	1	Buildings, structures and improvements, services, meters, mains	1,365,023	4.0%	54,601	
2	1	Non-residential building acquired after March 19, 2007	55,279	6.0%	3,317	/u
3	2	Mains acquired before 1988	166,925	6.0%	10,016	
4	3	Buildings acquired before 1988	4,741	5.0%	237	
5	6	Other buildings	213	10.0%	21	
6	7	Compression equipment acquired after February 22, 2005	141,567	15.0%	21,235	/u
7	8	Compression assets, office furniture, equipment	93,524	20.0%	18,705	/u
8	10	Transportation, computer equipment	21,193	30.0%	6,358	/u
9	12	Computer software, small tools	7,934	100.0%	7,934	/u
10	13	Leasehold improvements	656	N/A (1)	121	/u
11	17	Roads, sidewalk, parking lot or storage areas	1,118	8.0%	89	
12	38	Heavy work equipment	5,688	30.0%	1,706	/u
13	41	Storage assets	9,352	25.0%	2,338	/u
14	45	Computer hardware acquired after March 22, 2004 and before March 19, 2007	815	45.0%	367	
15	49	Transmission pipelines acquired after February 22, 2005	196,657	8.0%	15,733	/u
16	50	Computer hardware acquired after March 18, 2007	6,889	55.0%	3,789	/u
17	51	Distribution pipelines acquired after March 18, 2007	374,598	6.0%	22,476	/u
18	52	Computer hardware acquired after January 27, 2009 and before February 2011	1,038	100.0%	1,038	/u
19	Total		2,453,210		170,080	/u

Note:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2011

Line No.	Particulars	FTE (a)	($000's) Total Salaries [1] (b)	Total Variable Pay [2] (c)	Total Benefit (d)	
1	Management	1,010	92,966	20,528	36,562	/u
2	Analyst	261	16,223	1,763	10,568	/u
3	Unionized	881	66,877	2,458	30,707	/u
4	Non-Unionized	67	3,656	461	3,217	/u
5	Total	2,219	179,722	25,210	81,054	/u

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit	
6	Management	148,593	92,060	20,328	36,205	/u
7	Analyst	109,572	62,252	6,766	40,554	/u
8	Unionized	113,534	75,897	2,789	34,848	/u
9	Non-Unionized	110,050	54,858	6,912	48,280	/u
10	Average	128,866	80,983	11,360	36,523	/u

Note:

(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
Comparison of Cost of Service
Year Ending December 31

Line No.	Particulars ($000's)	Actual 2010	Board-Approved 2007	Difference
		(a)	(b)	(c)
1	Cost of gas	795,549	1,135,825	(340,276)
2	Operating and maintenance	351,634	326,222	25,412
3	Depreciation	190,176	173,780	16,396
4	Other financing	621	315	306
5	Property and capital taxes	65,131	67,709	(2,578)
6	Other expense	500	-	500
7	Income taxes	30,214	14,589	15,625
8	Cost of service excluding return	1,433,825	1,718,440	(284,615)

UNION GAS LIMITED
Actual Gas Purchase Expense
Year Ending December 31, 2010

Line No.	Particulars	Volume (TJ)	Cost ($000's)	% of Total Volume
		(a)	(b)	(c)
Section A				
	Supply Transportation			
1	Western Canadian Firm	97,681	157,720	
2	U.S. Firm	28,996	21,125	
3	Adjustments	-	(30)	
4	Total Supply Transport	126,677	178,815	
	Supply Commodity			
5	Western Canadian Firm	77,153	300,454	55%
6	U.S. Firm	28,996	119,682	21%
7	Ontario Delivered Supplies	14,595	64,642	10%
8	Northern Bundled T-Service	20,529	-	15%
9	Adjustments	-	-	0%
10	Other	-	-	0%
11	Total Supply Commodity	141,272	484,778	100%
	Storage			
12	STS and Related Services		14,586	
13	Total Supply at Cost		678,178	
Section B				
	Storage Inventory Change			
14	LNG	-	-	
15	Other Company Owned	3,067	15,777	
16	3rd Party	-	-	
17	Total Gas (to) from Storage	3,067	15,777	
Section C				
18	Total 3rd Party Storage		263	
19	Total Section A, B, & C		694,218	

UNION GAS LIMITED
Actual Gas Purchase Expense
Year Ending December 31, 2010

Line No.	Particulars	Volume (TJ) (a)	Cost ($000's) (b)	% of Total Volume (c)
	Gas Supply			
1	Total Supply at Cost	141,272	678,441	
2	Deferred Costs		123,882	
3	Total Gas Supply	141,272	802,323	
4	Gas (to) from Storage	3,067	15,777	
5	Winter Peaking Service		3,856	
6	Other Transportation		972	
7	Company Use Adj.		(13,301)	
8	Linepack		-	
9	Deferral Adjustment		(33,116)	
10	UFG Adjustment		17,264	
11	Accounting Adjustment		570	
12	Total Cost of Gas	144,339	794,345	
13	Less: Unregulated costs		(669)	
14			793,676	
15	Add: Costs related to short-term storage revenue		1,873	
16	Total Utility Cost of Gas		795,549	

UNION GAS LIMITED
Unaccounted for Gas Volume
For the Year Ending December 31, 2010

Line No.	Particulars	Volume (a)	Weighting (b)	Volume Weighted (c)
	Determination of Forecast UFG volume for 2010			
	3 year average of actual UFG (10^3 m^3):			
1	2008	143,880	50%	71,940
2	2007	203,713	33%	67,225
3	2006	154,015	17%	26,183
4	Average actual UFG volume			165,348
	3 year average of actual throughput (10^6 m^3):			
5	2008	34,978	50%	17,489
6	2007	33,446	33%	11,037
7	2006	29,843	17%	5,073
8	Average actual UFG throughput			33,599
9	UFG ratio for 2010 (line 4 / line 8 / 1,000)			0.492%
10	2010 total forecast throughput (10^6 m^3)			30,896
11	Estimated UFG volume for 2010 (10^3 m^3) (1)			152,047
12	Actual UFG volume for 2010 (10^3 m^3)			67,283
13	Actual UFG ($000's) (2)			13,686

Note:
(1) Line 9 * line 10 * 1,000.
(2) Calculated using EB-2009-0410 reference price of $257.161/$10^3$ m^3 for January to March; EB-2010-0040 reference price of $267.657/$10^3$$m^3$ for April to June; EB-2010-0201 reference price of $230.945/$10^3$ m^3 for July to September; and EB-2010-0265 reference price of $213.930/$10^3$$m^3$ for October to December.

UNION GAS LIMITED
Actual Unaccounted for Gas Volumes
Years Ending December 31, 2006-2011

Line No.	Particulars (10^3 m^3)	Board-Approved	Actual	
1	2006	142,322	154,015	
2	2007	147,478	203,713	
3	2008	147,478	143,880	
4	2009	147,478	201,845	
5	2010	147,478	67,283	
6	2011	147,478	35,668	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Administrator
Calender Year Ending December 31, 2010

Line No.	Particulars ($000's)	Actual 2010
1	Affiliate Services (Inbound & Outbound)	(720)
2	Audit Services	323
3	Bad Debt Expense	5,075
4	Business Development, Storage & Transmission	14,593
5	Corporate Adjustments	2,784
6	Distribution Operations	114,565
7	Employee & Labour Relations	101,853
8	Energy Conservation	22,627
9	Engineering, Construction & STO	42,472
10	Environment, Health & Governance	830
11	Executive	2,962
12	Finance	7,778
13	Government Affairs / Relations	1,303
14	Insurance	8,780
15	IT - Information Systems	10,956
16	IT - Information Technology Infrastructure	15,218
17	IT - Other	1,630
18	Legal	1,269
19	Marketing & Customer Care	54,864
20	Procurement / Supply Chain	2,226
21	Project Systems & Controls	187
22	Regulatory	10,990
23	Tax	1,112
24	Total	423,677
25	Capitalization	(60,267)
26	Non-Utility Allocation	(11,776)
27	Total Net Utility Operating and Maintenance Expense	351,634
28	Excess Utility Cross-Charge	(2,261)
29	Total Net Utility O&M Less Cross-Charge	349,373

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars ($000's)	Actual 2010	Board-Approved 2007	Difference	%
		(a)	(b)	(c)	(d)
1	Salaries/Wages	183,249	159,896	23,353	14.61%
2	Benefits	70,861	55,621	15,240	27.40%
3	Materials	9,631	9,132	499	5.47%
4	Employee Expenses/Training	11,783	12,798	(1,015)	(7.93%)
5	Contract Services	57,335	50,061	7,274	14.53%
6	Consulting	7,506	6,447	1,059	16.42%
7	General	21,211	20,645	566	2.74%
8	Transportation and Maintenance	7,892	7,523	369	4.90%
9	Company Used Gas	2,451	4,911	(2,460)	(50.09%)
10	Utility Costs	3,704	3,269	435	13.31%
11	Communications	6,780	7,969	(1,189)	(14.92%)
12	Demand Side Management Programs	16,438	11,874	4,564	38.43%
13	Advertising	1,860	2,255	(395)	(17.50%)
14	Insurance	8,507	7,004	1,503	21.46%
15	Donations	749	404	345	85.42%
16	Financial	2,077	2,884	(807)	(27.98%)
17	Lease	3,632	3,202	430	13.44%
18	Cost Recovery from Third Parties	(4,641)	(2,106)	(2,535)	120.38%
19	Computers	4,922	4,226	696	16.47%
20	Regulatory Hearing & OEB Cost Assessment	3,126	6,000	(2,874)	(47.90%)
21	Outbound Affiliate Services	(10,182)	(5,741)	(4,441)	77.36%
22	Inbound Affiliate Services	9,462	11,933	(2,471)	(20.71%)
23	Bad Debt	5,075	11,600	(6,525)	(56.25%)
24	Other	249	100	149	149.18%
25	Total Gross Operating and Maintenance Expense	423,677	391,907	31,770	8.11%
26	Indirect Capitalization	(46,289)	(51,528)	5,239	(10.17%)
27	Direct Capitalization	(13,978)	(7,350)	(6,628)	90.18%
28	Total Utility Operating and Maintenance Expense	363,410	333,029	30,381	9.12%
29	Non-Utility Allocations	(11,776)	(6,807)	(4,969)	73.00%
30	Total Net Utility Operating and Maintenance Expense	351,634	326,222	25,412	7.79%
31	Excess Utility Cross-Charge	(2,261)	(599)	(1,662)	277.46%
32	Total Net Utility O&M Less Cross-Charge	349,373	325,623	23,750	7.29%

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Salaries / Wages	
1	2010 Actual	183,249
2	2007 Board-Approved	159,896
3	Difference	23,353
	Reasons:	
4	Incentive accrual/payout	9,542
5	Merit increase	14,569
6	Severances (2010 variance)	(809)
7	Other	51
8	Total difference: 2010 Actual vs. 2007 Board-Approved	23,353
	Benefits	
9	2010 Actual	70,861
10	2007 Board-Approved	55,621
11	Difference	15,240
	Reasons:	
12	Increased non pension benefit costs	5,470
13	Increased pension benefit costs	9,170
14	WSIB Neer charge (2010)	600
15	Total difference: 2010 Actual vs. 2007 Board-Approved	15,240
	Materials	
16	2010 Actual	9,631
17	2007 Board-Approved	9,132
18	Difference	499
	Reasons:	
19	Odourant	303
20	Other	196
21	Total difference: 2010 Actual vs. 2007 Board-Approved	499

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Employee Expenses / Training	
1	2010 Actual	11,783
2	2007 Board-Approved	12,798
3	Difference	(1,015)
	Reasons:	
4	Relocation costs	(361)
5	Meals and accommodation expense	517
6	Travel	(405)
7	Training	(1,263)
8	Safety	517
9	Other	(20)
10	Total difference: 2010 Actual vs. 2007 Board-Approved	(1,015)
	Contract Services	
11	2010 Actual	57,335
12	2007 Board-Approved	50,061
13	Difference	7,274
	Reasons:	
14	Integrity work	760
15	Line locates	1,567
16	Maintenance	3,657
17	Other	1,290
18	Total difference: 2010 Actual vs. 2007 Board-Approved	7,274

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Consulting	
1	2010 Actual	7,506
2	2007 Board-Approved	6,447
3	Difference	1,059
	Reasons:	
4	IFRS costs	2,179
5	Other	(1,120)
6	Total difference: 2010 Actual vs. 2007 Board-Approved	1,059
	General	
7	2010 Actual	21,211
8	2007 Board-Approved	20,645
9	Difference	566
	Reasons:	
10	Cushion gas sale	(3,253)
11	Postage	473
12	Janitorial	589
13	Freight	77
14	Recycling / Waste	163
15	Permits / Cerifications	64
16	Security	744
17	Other	1,709
18	Total difference: 2010 Actual vs. 2007 Board-Approved	566

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Transportation and Maintenance	
1	2010 Actual	7,892
2	2007 Board-Approved	7,523
3	Difference	369
	Reasons:	
4	Volume and price	369
5	Total difference: 2010 Actual vs. 2007 Board-Approved	369
	Company Used Gas	
6	2010 Actual	2,451
7	2007 Board-Approved	4,911
8	Difference	(2,460)
	Reasons:	
9	Volume and price	(2,460)
10	Total difference: 2010 Actual vs. 2007 Board-Approved	(2,460)
	Utility Costs	
11	2010 Actual	3,704
12	2007 Board-Approved	3,269
13	Difference	435
	Reasons:	
14	Increased utility costs	435
15	Total difference: 2010 Actual vs. 2007 Board-Approved	435

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Communications	
1	2010 Actual	6,780
2	2007 Board-Approved	7,969
3	Difference	(1,189)
	Reasons:	
4	Telemetry cost reduction	(693)
5	Bell credits	(200)
6	Radio removal	(200)
7	Other	(96)
8	Total difference: 2010 Actual vs. 2007 Board-Approved	(1,189)
	Demand Side Management Programs	
9	2010 Actual	16,438
10	2007 Board-Approved	11,874
11	Difference	4,564
	Reasons:	
12	DSM program costs	4,564
13	Total difference: 2010 Actual vs. 2007 Board-Approved	4,564
	Advertising	
14	2010 Actual	1,860
15	2007 Board-Approved	2,255
16	Difference	(395)
	Reasons:	
17	Promotional items	(220)
18	Radio advertising	(163)
19	Other	(12)
20	Total difference: 2010 Actual vs. 2007 Board-Approved	(395)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Insurance	
1	2010 Actual	8,507
2	2007 Board-Approved	7,004
3	Difference	1,503
	Reasons:	
4	Higher insurance premiums	1,503
5	Total difference: 2010 Actual vs. 2007 Board-Approved	1,503
	Donations	
6	2010 Actual	749
7	2007 Board-Approved	404
8	Difference	345
	Reasons:	
9	Other	345
10	Total difference: 2010 Actual vs. 2007 Board-Approved	345
	Financial	
11	2010 Actual	2,077
12	2007 Board-Approved	2,884
13	Difference	(807)
	Reasons:	
14	Audit fees	(305)
15	Bad debt commission	(371)
16	Other	(131)
17	Total difference: 2010 Actual vs. 2007 Board-Approved	(807)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Lease	
1	2010 Actual	3,632
2	2007 Board-Approved	3,202
3	Difference	430
	Reasons:	
4	Storage leases	356
5	Other	74
6	Total difference: 2010 Actual vs. 2007 Board-Approved	430
	Cost Recovery from Third Parties	
7	2010 Actual	(4,641)
8	2007 Board-Approved	(2,106)
9	Difference	(2,535)
	Reasons:	
10	Injury / Damage recovery	(269)
11	Cost recovery	(2,266)
12	Total difference: 2010 Actual vs. 2007 Board-Approved	(2,535)
	Computers	
13	2010 Actual	4,922
14	2007 Board-Approved	4,226
15	Difference	696
	Reasons:	
16	Software maintenance	556
17	Other	140
18	Total difference: 2010 Actual vs. 2007 Board-Approved	696

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Regulatory Hearing & OEB Cost Assessment	
1	2010 Actual	3,126
2	2007 Board-Approved	6,000
3	Difference	(2,874)
	Reasons:	
4	Other	(2,874)
5	Total difference: 2010 Actual vs. 2007 Board-Approved	(2,874)
	Outbound Affiliate Services	
6	2010 Actual	(10,182)
7	2007 Board-Approved	(5,741)
8	Difference	(4,441)
	Reasons:	
9	Other	(4,441)
10	Total difference: 2010 Actual vs. 2007 Board-Approved	(4,441)
	Inbound Affiliate Services	
11	2010 Actual	9,462
12	2007 Board-Approved	11,933
13	Difference	(2,471)
	Reasons:	
14	Other	(2,471)
15	Total difference: 2010 Actual vs. 2007 Board-Approved	(2,471)

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2007 Board-Approved

Line No.	Particulars	($000's)
	Bad Debt	
1	2010 Actual	5,075
2	2007 Board-Approved	11,600
3	Difference	(6,525)
	Reasons:	
4	WACOG and bad debt experience	(6,525)
5	Total difference: 2010 Actual vs. 2007 Board-Approved	(6,525)
	Other	
6	2010 Actual	249
7	2007 Board-Approved	100
8	Difference	149
	Reasons:	
9	Other	149
10	Total difference: 2010 Actual vs. 2007 Board-Approved	149

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2010

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	191,720
2	Adjustments: vehicle depreciation through clearing	1,543
3	Provision for depreciation amortization and depletion	190,177

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2010

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	1,321		63
2	Intangible plant - Other	6,370		118
3		7,691		181
	Local Storage Plant			
4	Structures and improvements	2,593	3.30%	87
5	Gas holders - storage	4,574	2.68%	(35)
6	Gas holders - equipment	9,225	3.68%	339
7	Regulatory Overheads	114	30	4
8		16,506		395
	Storage:			
9	Land rights	32,062	2.23%	715
10	Structures and improvements	55,077	2.34%	1,289
11	Wells and lines	87,383	2.66%	2,324
12	Compressor equipment	218,629	3.19%	6,974
13	Measuring & regulating equipment	50,288	4.30%	2,163
14	Other Storage Equipment	821	20.00%	27
15	Regulatory Overheads	1,498	35	43
16		445,758		13,535
	Transmission:			
17	Land rights	37,673	2.00%	754
18	Structures and improvements	53,401	2.66%	1,421
19	Mains	1,038,740	2.37%	24,618
20	Compressor equipment	298,410	3.52%	10,504
21	Measuring & regulating equipment	141,533	3.61%	5,109
22	Regulatory Overheads	3,758	40	94
23		1,573,515		42,500
	Distribution - Southern Operations:			
24	Land rights	5,414	1.67%	90
25	Structures and improvements	101,031	2.91%	2,956
26	Services - metallic	109,884	3.69%	4,055
27	Services - plastic	734,964	3.18%	23,372
28	Regulators	70,793	3.30%	2,336
29	Regulator and meter installations	66,954	3.51%	2,350
30	Mains - metallic	397,468	2.54%	10,096
31	Mains - plastic	497,000	2.34%	11,629
32	Measuring & regulating equipment	28,951	4.64%	1,343
33	Meters	184,525	3.70%	6,828
34	Regulatory Overheads	12,685	35	362
35		2,209,669		65,417

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2010

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	8,951	1.68%	150
2	Structures & improvements	60,516	3.13%	1,917
3	Services - metallic	92,411	3.58%	3,308
4	Services - plastic	349,438	3.19%	11,147
5	Regulators	26,302	3.34%	878
6	Regulator and meter installations	28,975	3.50%	1,014
7	Mains - metallic	348,326	2.52%	8,778
8	Mains - plastic	198,719	2.35%	4,670
9	Compressor equipment	-		-
10	Measuring & regulating equipment	102,821	4.63%	4,761
11	Meters	52,213	3.67%	1,916
12	Regulatory Overheads	5,798	35	166
13		1,274,470		38,705
	General:			
14	Structures and improvements	41,261	2.13%	933
15	Office furniture and equipment	12,886	6.67%	859
16	Office equipment - computers	84,007	25.00%	21,002
17	Transportation equipment	40,898	10.07%	4,118
18	Heavy work equipment	14,071	4.55%	641
19	Tools and other equipment	31,858	6.67%	2,124
20	Communications equipment	13,252	6.67%	883
21	Communications structures	2,685	4.88%	131
22	Regulatory Overheads	2,957	10	296
23		243,875		30,987
24	Contributions in aid of construction	-		-
25	Sub-total	5,771,484		191,720
26	Total provision for depreciation and amortization	5,771,484		191,720
27	Depreciation through clearing			1,543
28		5,771,484		190,177

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation pro

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000's)	Actual 2010
	Determination of Taxable Income	
1	Utility income before interest and income taxes (1)	321,562
	Adjustments required to arrive at taxable utility income:	
2	Interest expense	(148,403)
3	Utility permanent differences	4,589
4		177,747
	Utility timing differences	
5	Capital Cost Allowance	(171,709)
6	Depreciation (2)	190,177
7	Depreciation through clearing (2)	1,543
8	Other	(49,911)
9	Gas Cost Deferral and Other (current)	(152,680)
10		(182,581)
11	Taxable income	(4,834)
	Calculation of Utility Income Taxes	
12	Income taxes (line 11 * line 18)	(1,498)
13	Deferred tax on Cost Deferrals	48,753
14	Deferred tax drawdown	(17,041)
15	Total taxes	30,214
	Tax Rates	
16	Federal tax	18.00%
17	Provincial tax	13.00%
18	Total tax rate	31.00%

Note:
(1) Exhibit F6, Tab 2, Schedule 1.
(2) Exhibit D6, Tab 4, Schedule 1.

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Calendar Year Ending December 31, 2010

Line No.	Class	Particulars ($000's)	Average CCA Balance (a)	Rate (%) (b)	Provision (c)
1	1	Buildings, structures and improvements, services, meters, mains	1,420,545	4.0%	56,822
2	1	Non-residential building acquired after March 19, 2007	51,543	6.0%	3,093
3	2	Mains acquired before 1988	177,580	6.0%	10,655
4	3	Buildings acquired before 1988	4,991	5.0%	250
5	6	Other buildings	237	10.0%	24
6	7	Compression equipment acquired after February 22, 2005	149,067	15.0%	22,360
7	8	Compression assets, office furniture, equipment	68,651	20.0%	13,730
8	10	Transportation, computer equipment	19,506	30.0%	5,852
9	12	Computer software, small tools	7,727	100.0%	7,727
10	13	Leasehold improvements	651	N/A [1]	113
11	17	Roads, sidewalk, parking lot or storage areas	1,215	8.0%	97
12	38	Heavy work equipment	4,726	30.0%	1,418
13	41	Storage assets	8,631	25.0%	2,158
14	45	Computer hardware acquired after March 22, 2004 and before March 19, 2007	1,481	45.0%	666
15	49	Transmission pipelines acquired after February 22, 2005	204,565	8.0%	16,365
16	50	Computer hardware acquired after March 18, 2007	2,859	55.0%	1,572
17	51	Distribution pipelines acquired after March 18, 2007	294,137	6.0%	17,648
18	52	Computer hardware acquired after January 27, 2009 and before February 2011	11,159	100.0%	11,159
19		Total	2,429,271		171,709

Note:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED
Salaries, Variable Pay, and Employee Benefits
Calendar Year Ended December 31, 2010

			($000's)		
Line No.	Particulars	FTE	Total Salaries [1]	Total Variable Pay [2]	Total Benefit
		(a)	(b)	(c)	(d)
1	Management	963	85,880	19,724	32,922
2	Analyst	276	18,269	1,697	8,437
3	Unionized	884	63,203	1,946	26,769
4	Non-Unionized	88	4,480	441	2,549
5	Total	2,211	171,832	23,808	70,677

	$/FTE	Average Yearly Compensation	Average Yearly Wage	Average Yearly Variable Pay	Average Yearly Benefit
6	Management	143,878	89,198	20,486	34,194
7	Analyst	102,835	66,143	6,144	30,547
8	Unionized	103,979	71,496	2,201	30,282
9	Non-Unionized	85,160	51,071	5,032	29,056
10	Average	120,466	77,727	10,769	31,970

Note:
(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
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2009

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	188,323
2	Adjustments: vehicle depreciation through clearing	1,150
3	Provision for depreciation amortization and depletion	187,173

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2009

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	1,321		83
2	Intangible plant - Other	6,370		123
3		7,691		206
	Local Storage Plant			
4	Structures and improvements	2,557	3.30%	84
5	Gas holders - storage	4,523	2.68%	121
6	Gas holders - equipment	8,170	3.68%	301
7	Regulatory Overheads		30	-
8		15,250		506
	Storage:			
9	Land rights	32,037	2.23%	714
10	Structures and improvements	54,419	2.34%	1,274
11	Wells and lines	87,032	2.66%	2,315
12	Compressor equipment	222,272	3.19%	7,090
13	Measuring & regulating equipment	48,293	4.30%	2,077
14	Other Storage Equipment		20.00%	-
15	Regulatory Overheads		35	-
16		444,053		13,470
	Transmission:			
17	Land rights	35,960	2.00%	719
18	Structures and improvements	52,662	2.66%	1,401
19	Mains	1,017,253	2.37%	24,109
20	Compressor equipment	297,445	3.52%	10,470
21	Measuring & regulating equipment	138,453	3.61%	4,998
22	Regulatory Overheads		40	-
23		1,541,773		41,697
	Distribution - Southern Operations:			
24	Land rights	5,191	1.67%	86
25	Structures and improvements	88,639	2.91%	2,594
26	Services - metallic	110,497	3.69%	4,077
27	Services - plastic	719,739	3.18%	22,888
28	Regulators	69,754	3.30%	2,301
29	Regulator and meter installations	62,269	3.51%	2,186
30	Mains - metallic	390,954	2.54%	9,930
31	Mains - plastic	481,293	2.34%	11,263
32	Measuring & regulating equipment	28,270	4.64%	1,312
33	Meters	174,333	3.70%	6,450
34	Regulatory Overheads		35	-
35		2,130,939		63,087

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2009

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	8,841	1.68%	149
2	Structures & improvements	50,377	3.13%	1,595
3	Services - metallic	92,008	3.58%	3,294
4	Services - plastic	340,599	3.19%	10,865
5	Regulators	24,896	3.34%	832
6	Regulator and meter installations	28,582	3.50%	1,000
7	Mains - metallic	342,165	2.52%	8,623
8	Mains - plastic	192,097	2.35%	4,514
9	Compressor equipment	670	3.34%	20
10	Measuring & regulating equipment	98,128	4.63%	4,543
11	Meters	50,719	3.67%	1,861
12	Regulatory Overheads		35	-
13		1,229,082		37,296
	General:			
14	Structures and improvements	41,369	2.13%	933
15	Office furniture and equipment	15,550	6.67%	1,037
16	Office equipment - computers	87,708	25.00%	21,927
17	Transportation equipment	42,574	10.07%	4,287
18	Heavy work equipment	13,103	4.55%	595
19	Tools and other equipment	33,128	6.67%	2,209
20	Communications equipment	13,908	6.67%	926
21	Communications structures	2,975	4.88%	147
22	Regulatory Overheads		10	-
23		250,315		32,061
24	Contributions in aid of construction	-		-
25	Sub-total	5,619,103		188,323
26	Total provision for depreciation and amortization	5,619,103		188,323
27	Depreciation through clearing			1,150
28		5,619,103		187,173

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2008

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	181,403
2	Adjustments: vehicle depreciation through clearing	1,150
3	Provision for depreciation amortization and depletion	180,253

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2008

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	2,102		101
2	Intangible plant - Other	9,370		123
3		11,472		224
	Local Storage Plant			
4	Structures and improvements	2,591	3.30%	85
5	Gas holders - storage	4,473	2.68%	120
6	Gas holders - equipment	7,663	3.68%	282
7	Regulatory Overheads		30	-
8		14,727		487
	Storage:			
9	Land rights	31,998	2.23%	714
10	Structures and improvements	52,743	2.34%	1,234
11	Wells and lines	86,371	2.66%	2,298
12	Compressor equipment	220,946	3.19%	7,048
13	Measuring & regulating equipment	47,427	4.30%	2,039
14	Other Storage Equipment		20.00%	-
15	Regulatory Overheads		35	-
16		439,485		13,333
	Transmission:			
17	Land rights	34,245	2.00%	685
18	Structures and improvements	48,252	2.66%	1,283
19	Mains	991,689	2.37%	23,503
20	Compressor equipment	222,927	3.52%	7,847
21	Measuring & regulating equipment	133,413	3.61%	4,817
22	Regulatory Overheads		40	-
23		1,430,526		38,135
	Distribution - Southern Operations:			
24	Land rights	4,839	1.67%	81
25	Structures and improvements	68,347	2.91%	2,021
26	Services - metallic	111,141	3.69%	4,102
27	Services - plastic	695,583	3.18%	22,120
28	Regulators	66,325	3.30%	2,189
29	Regulator and meter installations	53,865	3.51%	1,890
30	Mains - metallic	381,042	2.54%	9,678
31	Mains - plastic	459,888	2.34%	10,760
32	Measuring & regulating equipment	25,812	4.64%	1,198
33	Meters	169,612	3.70%	6,276
34	Regulatory Overheads		35	-
35		2,036,454		60,315

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2008

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	8,700	1.68%	146
2	Structures & improvements	41,069	3.13%	1,355
3	Services - metallic	91,149	3.58%	3,263
4	Services - plastic	330,989	3.19%	10,559
5	Regulators	23,732	3.34%	793
6	Regulator and meter installations	27,105	3.50%	949
7	Mains - metallic	334,249	2.52%	8,423
8	Mains - plastic	185,638	2.35%	4,362
9	Compressor equipment	1,341	3.34%	44
10	Measuring & regulating equipment	91,335	4.63%	4,229
11	Meters	49,256	3.67%	1,808
12	Regulatory Overheads		35	-
13		1,184,563		35,931
	General:			
14	Structures and improvements	40,461	2.13%	959
15	Office furniture and equipment	16,202	6.67%	1,119
16	Office equipment - computers	86,453	25.00%	21,960
17	Transportation equipment	46,705	10.07%	4,771
18	Heavy work equipment	13,763	4.55%	614
19	Tools and other equipment	32,864	6.67%	2,231
20	Communications equipment	16,062	6.67%	1,165
21	Communications structures	3,264	4.88%	159
22	Regulatory Overheads		10	-
23		255,774		32,978
24	Contributions in aid of construction	-		-
25	Sub-total	5,373,001		181,403
26	Total provision for depreciation and amortization	5,373,001		181,403
27	Depreciation through clearing			1,150
28		5,373,001		180,253

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	
	Total provision for depreciation and	
1	amortization before adjustments (per page 3)	169,614
2	Adjustments: vehicle depreciation through clearing	1,150
3	Provision for depreciation amortization and depletion	168,464

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)
	Intangible plant:			
1	Franchises and consents	2,102		102
2	Intangible plant - Other	9,370		123
3		11,472		225
	Local Storage Plant			
4	Structures and improvements	2,514	3.30%	83
5	Gas holders - storage	4,473	2.68%	120
6	Gas holders - equipment	7,618	3.68%	280
7	Regulatory Overheads		30	-
8		14,605		483
	Storage:			
9	Land rights	31,977	2.23%	713
10	Structures and improvements	50,981	2.34%	1,207
11	Wells and lines	85,420	2.66%	2,278
12	Compressor equipment	220,592	3.19%	7,103
13	Measuring & regulating equipment	47,149	4.30%	2,033
14	Other Storage Equipment		20.00%	-
15	Regulatory Overheads		35	-
16		436,119		13,334
	Transmission:			
17	Land rights	33,067	2.00%	661
18	Structures and improvements	44,390	2.66%	1,181
19	Mains	943,264	2.37%	22,355
20	Compressor equipment	143,728	3.52%	5,059
21	Measuring & regulating equipment	127,194	3.61%	4,592
22	Regulatory Overheads		40	-
23		1,291,643		33,848
	Distribution - Southern Operations:			
24	Land rights	4,549	1.67%	76
25	Structures and improvements	61,520	2.91%	1,809
26	Services - metallic	111,196	3.69%	4,103
27	Services - plastic	668,617	3.18%	21,262
28	Regulators	62,920	3.30%	2,077
29	Regulator and meter installations	49,546	3.51%	1,739
30	Mains - metallic	371,264	2.54%	9,430
31	Mains - plastic	442,423	2.34%	10,353
32	Measuring & regulating equipment	23,410	4.64%	1,085
33	Meters	166,196	3.70%	6,149
34	Regulatory Overheads		35	-
35		1,961,641		58,083

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant [1]	Rate (%)	Provision
		(a)	(b)	(c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	8,559	1.68%	144
2	Structures & improvements	42,493	3.13%	1,410
3	Services - metallic	89,459	3.58%	3,203
4	Services - plastic	320,028	3.19%	10,209
5	Regulators	22,799	3.34%	761
6	Regulator and meter installations	25,237	3.50%	883
7	Mains - metallic	322,582	2.52%	8,129
8	Mains - plastic	181,132	2.35%	4,257
9	Compressor equipment	1,341	3.34%	45
10	Measuring & regulating equipment	85,943	4.63%	3,979
11	Meters	48,777	3.67%	1,790
12	Regulatory Overheads		35	-
13		1,148,350		34,810
	General:			
14	Structures and improvements	37,476	2.13%	926
15	Office furniture and equipment	17,600	6.67%	1,130
16	Office equipment - computers	61,893	25.00%	17,978
17	Transportation equipment	45,300	10.07%	4,669
18	Heavy work equipment	14,809	4.55%	647
19	Tools and other equipment	31,251	6.67%	2,121
20	Communications equipment	18,543	6.67%	1,201
21	Communications structures	3,263	4.88%	159
22	Regulatory Overheads		10	-
23		230,135		28,831
24	Contributions in aid of construction	-		-
25	Sub-total	5,093,965		169,614
26	Total provision for depreciation and amortization	5,093,965		169,614
27	Depreciation through clearing			1,150
28		5,093,965		168,464

Note:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.