uniongas

June 7, 2012

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

**RE: EB-2011-0210 – Union Gas Limited – 2013 Rates Application – Undertaking Responses**

Dear Ms. Walli,

Please find attached a complete package of the responses to undertakings from Union's EB-2011-0210 technical conference.

If you have any questions, please contact me at (519) 436-5476.

Yours truly,

*[original signed by Joanne Clark for]*

Chris Ripley
Manager, Regulatory Applications

cc: Crawford Smith, Torys
EB-2011-0210 Intervenors

UNION GAS LIMITED

Undertaking of Mr. Wolnik
To Ms. Van Der Paelt

Please advise what proportion the commodity represents of total revenue.

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| | 2007 Actuals | 2008 Actuals | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Forecast | 2013 Forecast |
|---|---|---|---|---|---|---|---|
| Total Power Revenue | 26.8 | 26.3 | 29.0 | 32.2 | 32.7 | 29.7 | 29.5 |
| Total Power Commodity Revenue | 8.6 | 5.8 | 4.1 | 4.8 | 4.9 | 4.0 | 3.9 |
| % of Commodity vs Total Revenue | 32.1% | 22.1% | 14.1% | 14.9% | 15.0% | 13.5% | 13.2% |

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please provide both equations referred to in the response, including the regression statistics, and all the explanatory variables used.

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The updated FEI curve (including *2011 actuals*) equation is:

$$FEI = 0.0002174884554047\ Time^2 + 0.0008452010552058\ Time + 0.7331471264272360$$

The persons per household estimates are obtained from a simple trend line. The updated (including *2011 actuals*) equation is:

$$PPH = -0.032370\ Time + 3.297509$$

t statistics -10.6 76.8

The R square, mean absolute percent error (MAPE) and the mean absolute deviation (MAD), shown in the tables below, indicate the estimates fit well with the observed data. The updated data is similar to the original forecast evidence which did not include the 2011 actual data.

**FEI Fitted Line**

| Statistics | Original Evid. | Updated[1] |
|---|---|---|
| $R^2$ | 0.97 | 0.97 |
| MAPE | 0.5% | 0.6% |
| MAD | 0.000 | -0.001 |

**PPH Trend Line**

| Statistics | Original Evid. | Updated[1] |
|---|---|---|
| $R^2$ | 0.91 | 0.90 |
| MAPE | 1.6% | 1.7% |
| MAD | 0.000 | 0.000 |

Note 1 - updated fitted line incorporating the 2011 actuals

# UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please provide actual 2011 and forecast 2012 and 2013 figures for each of the residential equations used to forecast the residential volumes (use and volume shown as EQN. 1 and 2).

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## Econometric Demand Equation Estimates [1]

| | Southern Residential | | Northern Residential | |
|---|---|---|---|---|
| Year | Use Eqn: $m^3$ | Volume Eqn: $10^3m^3$ | Use Eqn: $m^3$ | Volume Eqn: $10^3m^3$ |
| Actual 2011 | 2,331 | 2,211,181 | 2,348 | 664,638 |
| Predicted 2011 | 2,327 | 2,192,507 | 2,329 | 665,913 |
| 2012 Frcst. [2] | 2,270 | 2,198,716 | 2,286 | 675,635 |
| 2013 Frcst. [2] | 2,140 | 2,141,659 | 2,122 | 647,819 |

Notes:

(1) Estimates that are subsequently averaged and adjusted for DSM plan impacts.

(2) The 2012 forecast estimates assume the 55:45 weather normal and the 2013 forecast assumes the 20-year declining trend weather normal.

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please advise whether Union could discontinue the average use per customer deferral account or similar account when it files a proposal for the next multi-year incentive regulatory plan; to provide responses to J.DV-4-1-1 parts (b) and (c).

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Union could close the existing average use deferral account and apply for a similar account with any potential application for its next multi-year incentive regulation framework. Board approval of the continuation of the average use deferral account as part of Union's 2013 Rates application is not required for it, or a similar account, to be a component of any application for its next multi-year incentive regulation framework.

The presence of an AU Deferral Account in 2013 does not eliminate the forecast risk associated with the margin impact of the average use forecast for the applicable general service customer classes. The AU Deferral Account is not proposed to be used for 2013 rates.

## UNION GAS LIMITED

Undertaking of Mr. Brett
To Mr. Gardiner

Please provide data on split from attachment data for each year of 10-year period.

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### RESIDENTIAL MULTI-FAMILY ATTACHMENTS

| | Multi-Family | | Share of Tot. Residential Attachments | |
|---|---|---|---|---|
| Year | Total | Cumulative | Total | Cumulative |
| 1995 | 3,528 | 3,528 | 12% | 12% |
| 1996 | 3,875 | 7,403 | 11% | 12% |
| 1997 | 4,203 | 11,606 | 12% | 12% |
| 1998 | 3,975 | 15,581 | 13% | 12% |
| 1999 | 2,868 | 18,449 | 12% | 12% |
| 2000 | 2,681 | 21,130 | 12% | 12% |
| 2001 | 3,000 | 24,130 | 16% | 12% |
| 2002 | 4,267 | 28,397 | 15% | 13% |
| 2003 | 4,445 | 32,842 | 16% | 13% |
| 2004 | 4,947 | 37,789 | 17% | 14% |
| 2005 | 5,109 | 42,898 | 20% | 14% |
| 2006 | 5,323 | 48,221 | 22% | 15% |
| 2007 | 4,719 | 52,940 | 22% | 15% |
| 2008 | 4,615 | 57,555 | 21% | 15% |
| 2009 | 2,327 | 59,882 | 14% | 15% |
| 2010 | 1,978 | 61,860 | 11% | 15% |
| 2011 | 1,938 | 63,798 | 11% | 15% |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please provide an actual numeric example of each of the categories to show how net revenue is calculated; to show all the costs associated with the transaction.

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Below are the three categories that support Exchange revenue.

Base Exchange:

Example: Union sells Dawn-Niagara exchange for 20,000 GJ/d for one month at $0.35/GJ. Union serves this exchange with TCPL IT transportation.

| | |
|---|---|
| Revenue from Dawn-Niagara Exchange | $217,000 |
| Cost from Dawn-Niagara Exchange | |
| IT Cost | 180,476 |
| Fuel Cost | 6,448 |
| Pressure Charge | 12,115 |
| Total Cost | 199,039 |
| | |
| Net Revenue | $17,961 |

Capacity Assignment:

Example: Union assigns to a third party 20,000 GJ/d of Empress-Union EDA capacity for one month. The same counterparty also agrees to accept Union's supply at Empress and redelivers the equivalent quantity to Dawn. Customer pays Union $0.04/GJ. In this example, prior to the capacity assignment, the gas is not required in the EDA and would have been transported to Dawn for storage using TCPL STS service.

| | |
|---|---|
| Revenue from pipe release | $240,000 |
| Costs from pipe release | - |
| | |
| Net Revenue | $240,000 |

RAM Optimization:

Example: Union sells Dawn-Niagara exchange for 20,000 GJ/d for one month at $0.35/GJ. Union serves this exchange with TCPL IT transportation funded by RAM credits.

| | |
|---|---|
| Revenue from Dawn-Niagara exchange | $217,000 |
| IT minimum charge | 8,643 |
| Fuel Cost | 6,448 |
| Pressure Charge | 12,115 |
| Total Costs | 27,206 |
| Net Revenue | $189,784 |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please advise whether Union will include a RAM forecast in the S&T forecast; since the future of the FT RAM program is unknown, does Union agree the deferral account for transportation exchange revenue is warranted.

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a) As indicated at Exhibit J.C-4-7-9, Union would consider including FTRAM revenue in its 2013 S&T revenue forecast with a deferral account to capture any variance between the revenue attributable to FTRAM included in rates and the actual revenues attributable to FTRAM. The deferral account is necessary because of the uncertainty regarding the continuation of TCPL's FTRAM program and Union's ability to optimize the FTRAM program.

b) Union does not support the creation of a deferral account that captures transactional transportation margins in general.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Van Der Paelt

Please provide historic numbers and basis for forecast.

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| Interruptible Revenues ($Millions) | 2007 Actual | 2008 Actual | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Forecast | 2013 Forecast |
|---|---|---|---|---|---|---|---|
| Northern NUGS | 0.37 | 0.32 | 0.36 | 0.44 | 0.48 | 0.55 | 0.43 |
| CES Projects | 0.25 | 0.75 | - | - | - | - | 0.05 |
| OPGI Lennox | 4.90 | 2.11 | 0.67 | 0.79 | 0.86 | - | - |
| South | 0.16 | 0.03 | 0.02 | 0.04 | 0.02 | - | - |
| Total | 5.69 | 3.21 | 1.05 | 1.26 | 1.36 | 0.55 | 0.48 |

The interruptible service forecast is part of the detailed bottom-up forecasts Union prepares for the large contract customers. Union provides historical consumption information for the customer and determines through discussion if plant operations and anticipated consumption are expected to change. The account managers reflect those changes, if any are required, into the forecast.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Cameron

Please advise how much was turned back and how much was kept over the period shown in the tables.

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Please see Attachment.

| | Transportation Capacity Quantity (GJ/d) | | | | Quantity Turned Back or Expired (GJ/d) | | | | Quantity Expired (GJ/d) | | | | Quantity Turned Back (GJ/d) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | CDA | EDA | NCDA | Total Eastern Zone | CDA | EDA | NCDA | Total Eastern Zone | CDA | EDA | NCDA | Total Eastern Zone | CDA | EDA | NCDA | Total Eastern Zone |
| 01-Nov-06 | 201,881 | 85,989 | 11,039 | 298,909 | | | | | | | | | | | | |
| 01-Nov-07 | 91,870 | 85,989 | 11,039 | 188,898 | 110,011 | - | - | 110,011 | 71,735 | | | 71,735 | 38,276 | | | 38,276 |
| 01-Nov-08 | 71,327 | 85,989 | 11,039 | 168,355 | 20,543 | - | - | 20,543 | 4,846 | | | 4,846 | 15,697 | | | 15,697 |
| 01-Nov-09 | 71,327 | 61,156 | 11,039 | 143,522 | - | 24,833 | - | 24,833 | | 20,188 | | 20,188 | | 4,645 | | 4,645 |
| 01-Nov-10 | 71,327 | 61,156 | 11,039 | 143,522 | - | - | - | - | | | | 0 | | | | - |
| 01-Nov-11 | 71,327 | 59,251 | 10,756 | 141,334 | - | 1,905 | 283 | 2,188 | | | | 0 | | | | - |
| 01-Nov-12* | 67,327 | 59,251 | 10,756 | 137,334 | 4,000 | - | - | 4,000 | 0 | 0 | 0 | 0 | 4,000 | 0 | 0 | 4,000 |

Note: Nov 1, 2012 subject to change

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Cameron

Please explain whether the system has ability to separate off-peak storage balancing those short-term accounts.

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Yes, Union has the ability. However, the short-term storage balancing account, as currently framed, does not differentiate between the use of utility and non-utility space, and, as a result, Union has not identified the asset used to provide off-peak services – using either utility or non-utility asset results in a 90/10 sharing. In the future, if there is a different accounting treatment of off-peak use of utility space and non-utility space, Union would differentiate between the assets to provide service.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please advise whether Washington 10 a receipt point on the Chicago-to-Dawn Vector contract; whether there is a documented procedure for capacity release.

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Union's Chicago to Dawn Vector transportation contracts include all points on the Vector system as receipt points, including Washington 10, however, gas typically flows from Chicago to Dawn.

Union does not have a documented procedure regarding decisions to release utility transportation capacity. Union's process is:

1) On a monthly basis, Gas Supply reviews the revised forecast supply position, which incorporates (amongst other items) the most up to date actual information available as well as forecast weather for the current and/or upcoming season.
2) If required, a recommendation is made to reduce the planned supply purchases and to obtain internal approval.
3) Union will conduct a Request for Proposals (RFP) for the excess impacted transportation capacity. The winner of the RFP will be assigned the capacity.
4) For U.S. pipelines, the winning RFP bid would be posted as per FERC guidelines (when applicable) for the relevant pipe.
5) The revenue received through the RFP is credited to the UDC deferral account.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please provide a numeric example for the last three years that demonstrates that keeping the space empty has saved ratepayers money.

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The table below captures the revenue from selling gas molecules in the summer months, and the cost of purchasing gas molecules in the winter months for the last three years.

Table 1

| | Sell Gas (July) | Buy Gas (Jan) | Net Cost ($ per GJ) |
|---|---|---|---|
| 2010/11 | 4.59 | 5.64 | (1.05) |
| 2011/12 | 4.96 | 5.45 | (0.49) |
| 2012/13 | 2.58 | 3.52 | (0.94) |

# UNION GAS LIMITED

Undertaking of Ms. Girvan
To Ms. Cameron

Please explain how year-to-date S&T revenue is trending, relative to 2012 forecast.

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UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas

| Line No. | Particulars ($000's) | Actual 2012 (Q1) (a) | Forecast 2012 (Q1) (b) | Difference (c) |
|---|---|---|---|---|
| | Transportation | | | |
| 1 | M12 Transportation | 33,486 | 33,595 | (109) |
| 2 | M12-X Transportation | 1,104 | 1,107 | (3) |
| 3 | C1 Long-term Transportation | 1,795 | 1,708 | 87 |
| 4 | C1 Short-term Transportation and Exchanges | 17,879 | 11,595 | 6,284 |
| 5 | C1 Rebate Program | - | - | - |
| 6 | M13 Transportation | 76 | 91 | (15) |
| 7 | M16 Transportation | 183 | 204 | (21) |
| 8 | Other S&T Revenue | 257 | 267 | (10) |
| 9 | Total Transportation Revenue | 54,780 | 48,567 | 6,213 |
| | Storage | | | |
| 10 | Short-term Storage Services | 2,638 | 1,602 | 1,036 |
| 11 | Off-Peak Storage/Balancing/Loan Services | 447 | 500 | (53) |
| 12 | Total Storage Revenue | 3,085 | 2,102 | 983 |
| 13 | Total S&T Revenue | 57,865 | 50,669 | 7,196 |

UNION GAS LIMITED

Undertaking of Mr. McIntosh
To Mr. Gardiner

Please provide the updated summary statistics table for each of the Northern and Southern Zones.

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Union South

Weather normal forecast estimate versus actual annual level
11 Observations: estimates for 2001 to 2011 inclusive

| | 30 yr Avg. | 20 Yr DT | 55:45 Blend |
|---|---|---|---|
| Root Mean Square Error: RMSE | 261 | 195 | 203 |
| Average Variance from Actual | 194 | -37 | 90 |
| Std Deviation of Variance | 183 | 201 | 191 |
| Mean Percent Error | -5.5% | 0.8% | -2.7% |

Union North

Weather normal forecast estimate versus actual annual level
11 Observations: estimates for 2001 to 2011 inclusive

| | 30 yr Avg. | 20 Yr DT | 55:45 Blend |
|---|---|---|---|
| Root Mean Square Error: RMSE | 423 | 274 | 328 |
| Average Variance from Actual | 344 | 40 | 207 |
| Std Deviation of Variance | 257 | 285 | 267 |
| Mean Percent Error | -7.4% | -1.1% | -4.5% |

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Gardiner

Please provide revenue differences between scenarios and 20-year trend-based revenues.

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Attachment 1 in the response to Exhibit J.C-1-14-1 provides the total revenue differences for the three blended normal scenarios versus the 20-year declining trend normal for the year 2013.

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Van Der Paelt

Please provide number of M1 and M2 customers that are manufacturers.

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Manufacturers by General Service Rate Class
from Billing System Enquiry June 1 2012

| | | |
|---|---|---|
| Union South | Rate M1 | 6,718 |
| | Rate M2 | 1,505 |
| | Sub-Total | 8,223 |
| Union North | Rate 01 | 1,150 |
| | Rate 10 | 247 |
| | Sub-Total | 1,397 |
| All General Service Rates Classes | | 9,620 |

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Van Der Paelt

Please provide overrun forecast for all markets.

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| Market ($Millions) | 2007 Actual | 2008 Actual | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Forecast | 2013 Forecast |
|---|---|---|---|---|---|---|---|
| Power | 0.0 | 0.0 | 0.0 | 0.3 | 0.6 | 0.0 | 0.0 |
| Steel/Chem/Ref | 0.3 | 0.4 | 0.4 | 0.3 | 0.4 | 0.0 | 0.0 |
| LCI/Key | 1.6 | 1.1 | 1.0 | 1.1 | 1.2 | 0.5 | 0.6 |
| Greenhouse | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 |
| Grand Total | 2.1 | 1.7 | 1.5 | 1.8 | 2.4 | 0.5 | 0.6 |

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Cameron

Please clarify the extent to which services were used after NGEIR to optimize the value of disintegrated assets; to provide a list of the items that were available before NGEIR, a list of the items that are available and used after NGEIR to optimize both utility and non-utility, and a list of the services that Union is proposing to apply in 2013 and beyond to optimize the value of the utility and non-utility portions of integrated storage assets; to advise whether Union can provide any of these services listed in Attachment 1 for a period of two years or more; including multi-year gas loans.

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Union's services from its storage assets are divided into 5 categories: long-term peak storage, short-term peak storage, off peak storage, balancing, Enbridge LBA and loans. The services available did not change as a result of NGEIR. The services do not include the ex-franchise power services ordered by the Board in NGEIR as referenced at Exhibit JT1.18.

While NGEIR determined that revenue from long-term peak storage is no longer subject to deferral, Union has continued to include all revenue from off peak storage, balancing, Enbridge LBA and loans in the short-term storage and balancing deferral account, regardless of the underlying storage asset providing the service (utility or non-utility) or term (See JT1.10).

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Cameron

Please break out activities for Bluewater to Dawn, St. Clair to Dawn.

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When the forecast process was completed, the St. Clair Line was still considered a non-utility asset and as a result Union did not include any St. Clair to Dawn activities in its 2012 or 2013 forecast. All forecast utilization in JC-4-14-2 is for the Bluewater to Dawn transportation path. Union expects that the 2013 utilization will be consistent with 2012 utilization, once the existing lease line is replaced in early 2013.

Union expects that the St. Clair to Dawn throughput in 2011 will continue into 2012 and 2013.

Please note that the footnote (3) at the bottom of Attachment 1 should be deleted.

UNION GAS LIMITED

Undertaking of Mr. Millar
To Ms. Elliott

Re: Pigging, please advise whether “Practical” means feasible or cost-effective.

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In the case of pigging, practical means feasible which as clarified on page 124 of the Day 1 transcript, refers to “whether it’s physically possible to do it on those lines”.

Factors that deem a pipeline as not being piggable or not worth trying to make piggable are engineering related such as pipe diameter, length of the pipeline, operating characteristics (i.e. flow rates and pressure), the pipeline components such as elbows, reducers, filters, valves, etc. that are installed within the piping system and the potential for customer outage.

UNION GAS LIMITED

Undertaking of Mr. Millar
To Ms. Cummings

Please confirm there were no capital expenditures for station asset integrity from 2007 to 2010.

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Prior to 2011, station integrity costs were included in Union's maintenance capital budget and were not separately identified as integrity costs.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Canniff

Please provide a list of all projects to improve efficiency.

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Attached is a listing of all initiatives with 2008-2012 amounts identified by year.

List of Items Included in Productivity Evidence Tables
Sorted by 2012 Highest to Lowest
$ Millions

ALL ITEMS (Table 1)

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| Grand Total | 8.233 | 29.324 | 41.758 | 52.368 | 40.527 |
| Sub-total for items originally identified in 2008 | 3.265 | 13.983 | 20.879 | 19.661 | 18.167 |
| Sub-total for items originally identified in 2009 | 4.968 | 15.341 | 16.079 | 25.101 | 17.567 |
| Sub-total for items originally identified in 2010 | | | 4.800 | 7.606 | 4.793 |

O&M ITEMS (Table 2)

| Year Identified | | Description | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|
| 2008 | | Sales and Marketing Realignment | 0.416 | 2.722 | 3.170 | 3.382 | 3.585 |
| 2008 | | Field Work Effectiveness | 0.400 | 2.200 | 3.175 | 3.175 | 3.375 |
| 2009 | | Wireless Voice Modernization Project | | 0.125 | 0.903 | 1.250 | 1.250 |
| 2008 | | IT Governance/Demand Management | 0.050 | 0.458 | 0.875 | 0.865 | 0.865 |
| 2008 | | Management & Administration | | 0.760 | 0.760 | 0.760 | 0.760 |
| 2008 | | Customer Attachment Process Simplicity Initiative | 0.178 | 0.582 | 0.582 | 0.582 | 0.582 |
| 2008 | | Reduction of leased buildings | | 0.202 | 0.415 | 0.415 | 0.415 |
| 2010 | | Work and resource strategy | | | 0.100 | 0.243 | 0.379 |
| 2008 | | Consolidation of warehouse operations | | 0.081 | 0.362 | 0.362 | 0.362 |
| 2008 | | Banner Renegotiation | | | 0.358 | 0.348 | 0.271 |
| 2008 | | Telemetry improvements | | 0.365 | 0.350 | 0.350 | 0.250 |
| 2008 | | Sales and marketing vacancies | 0.280 | 0.180 | 0.180 | 0.180 | 0.180 |
| 2008 | | Energy conservation awareness/reductions | | 0.140 | 0.140 | 0.140 | 0.167 |
| 2008 | | Reduction of 2 FTE - merge FSS & RCS | 0.165 | 0.165 | 0.165 | 0.165 | 0.165 |
| 2009 | | Meter Reading Contract Renewal | | 0.162 | 0.162 | 0.162 | 0.162 |
| 2008 | | Reduce severance budget to historical levels | | | 0.150 | 0.150 | 0.150 |
| 2008 | | Improve Planning and Dispatch post implementation | | 0.125 | 0.125 | 0.125 | 0.150 |
| 2008 | | Reduce consulting spend | | | 0.150 | 0.150 | 0.150 |
| 2010 | | Major Projects - Reorganization | | | 0.150 | 0.150 | 0.150 |
| 2008 | | Community events efficiencies | | 0.136 | 0.136 | 0.136 | 0.136 |
| 2008 | | Geographic Information System | | | | 0.055 | 0.132 |
| 2008 | | Contract savings - ServiceMaster | 0.129 | 0.129 | 0.129 | 0.129 | 0.129 |
| 2010 | | Upsell self serve | | | - 0.235 | 0.062 | 0.124 |
| 2009 | | Transformational Engineering - Project benefits | | | 0.115 | 0.115 | 0.115 |
| 2009 | | In Situ Module changes | | 0.243 | 0.243 | 0.211 | 0.113 |
| 2008 | | Overall Employee Effectiveness, Storage and Transmission Operations | | | 0.100 | 0.100 | 0.100 |
| 2008 | | Reduce 1 project support role | 0.100 | 0.100 | 0.100 | 0.100 | 0.100 |
| 2008 | | Reduce peak coverage for Gas Distribution Access Rule | 0.100 | 0.100 | 0.100 | 0.100 | 0.100 |
| 2008 | | Eliminate Billing Support Manager | | 0.090 | 0.090 | 0.090 | 0.090 |
| 2008 | | Tax Planning | | 0.088 | 0.088 | 0.088 | 0.088 |
| 2008 | | Optimize resources | | 0.064 | 0.085 | 0.085 | 0.085 |
| 2008 | | Reduce Integrated Gas Supply Plan role | | 0.084 | 0.084 | 0.084 | 0.084 |
| 2009 | | Single source | | | 0.080 | 0.080 | 0.080 |
| 2008 | | Centrally Budgeted Salary Adjustment | | 0.078 | 0.078 | 0.078 | 0.078 |
| 2008 | | Reduce support functions | | 0.075 | 0.075 | 0.075 | 0.075 |
| 2009 | | Paper Savings - Corporate Head Office | | 0.016 | 0.016 | 0.065 | 0.065 |
| 2008 | | Budget & Planning Process | | 0.060 | 0.060 | 0.060 | 0.060 |
| 2008 | | Implement Identity Management Software | | | 0.030 | 0.060 | 0.060 |
| 2008 | | Billing Support Quality Assurance program | | 0.060 | 0.060 | 0.060 | 0.060 |
| 2008 | | External Corrosion Direct Assessment program | | 0.045 | 0.060 | 0.060 | 0.060 |
| 2009 | | Auto Service Order Close - Enhancements | | | 0.057 | 0.057 | 0.057 |
| 2008 | | Reduction of contract role for corrosion engineer | | 0.056 | 0.056 | 0.056 | 0.056 |
| 2010 | | Testing reduction | | | 0.056 | 0.056 | 0.056 |
| 2009 | | Master Summary Billing Service Offering | | | - 0.038 | 0.045 | 0.053 |
| 2008 | | Convert Old Communications Technology to New | | 0.100 | 0.125 | 0.050 | 0.050 |
| 2008 | | Reduce HR legal spend (arbitration cases) | | | 0.047 | 0.047 | 0.047 |
| 2009 | | Eliminate Creative Manager | | 0.047 | 0.047 | 0.047 | 0.047 |
| 2008 | | Send fewer Gas Distribution Access Rule letters | | 0.025 | 0.040 | 0.040 | 0.040 |
| 2009 | | System Upgrade and Efficiencies for Pipeline Integrity | | | 0.040 | 0.040 | 0.040 |
| 2008 | | Reduce consulting opportunities | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 |
| 2008 | | QX Self Locates (Windsor and Waterloo) | 0.035 | 0.030 | 0.030 | 0.030 | 0.030 |
| 2008 | | Outsource facility administration work to ServiceMaster | 0.030 | 0.026 | 0.026 | 0.026 | 0.026 |
| 2008 | | Reduce employee expenses with FTE reductions | 0.025 | 0.025 | 0.025 | 0.025 | 0.025 |
| 2008 | | Provide event correlation | | | 0.025 | 0.025 | 0.025 |
| 2008 | | Mobius - View Direct - shift to FileNet | | 0.024 | 0.024 | 0.024 | 0.024 |
| 2008 | | Mapping Process Procedures/ Landbase Submissions Improvements | | 0.024 | 0.024 | 0.024 | 0.024 |
| 2008 | | Eliminate For a Fee Chart Reading Services | | 0.023 | 0.023 | 0.023 | 0.023 |
| 2008 | | Finish backlog mapping | 0.010 | 0.021 | 0.021 | 0.021 | 0.021 |
| 2008 | | Reduced support for Contract Admin process | 0.021 | 0.021 | 0.021 | 0.021 | 0.021 |
| 2009 | | Refine Ontario One Call Locate coverage areas | | 0.020 | 0.020 | 0.020 | 0.020 |

List of Items Included in Productivity Evidence Tables
Sorted by 2012 Highest to Lowest
$ Millions

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2008 | | New Housing Penetration - Annual to bi-annual survey | 0.018 | | 0.018 | | 0.018 |
| 2008 | | Document policies & procedures - dist planning | 0.016 | 0.016 | 0.016 | 0.016 | 0.016 |
| 2008 | | Fleet - Adjust based on replacement role salary | 0.013 | 0.016 | 0.016 | 0.016 | 0.016 |
| 2008 | | Spectra to coordinate and pay for EEA study | 0.015 | 0.015 | 0.015 | 0.015 | 0.015 |
| 2008 | | Cross Section Penetration Survey - reduce | | 0.009 | 0.009 | 0.009 | 0.009 |
| 2008 | | Automate consolidation | | | 0.007 | 0.007 | 0.007 |
| 2008 | | Reduce Spectra reports | | | 0.007 | 0.007 | 0.007 |
| 2008 | | Bring outside training in to reduce training costs | | | 0.005 | 0.005 | 0.005 |
| 2008 | | Automate cash flow process | | | 0.004 | 0.004 | 0.004 |
| 2008 | | Commit to multi-yr contract with Send Out | | | 0.003 | 0.003 | 0.004 |
| 2008 | | Streamline SOX testing | | | 0.004 | 0.004 | 0.004 |
| 2008 | | IT Maintenance Eliminations | 0.001 | 0.001 | 0.002 | 0.002 | 0.002 |
| 2008 | | Employee Spending | 0.806 | 2.340 | 1.362 | | |
| 2008 | | Deliver Ontario Power Authority commercial Conservation Demand Management Programs | | 0.150 | 0.172 | | |
| 2008 | | Add to staff for Great Lakes Strategy | | - 0.065 | | | |
| 2010 | | Intelliresponse | | | - 0.016 | - 0.016 | - 0.016 |
| 2008 | | Dawn to Parkway Optimization | | | - 0.051 | - 0.051 | - 0.066 |
| 2008 | | Add to staff 2 for storage/Great Lakes Strategy | - 0.018 | - 0.077 | - 0.077 | - 0.039 | - 0.085 |
| | O&M Total | | 2.820 | 12.512 | 15.961 | 15.536 | 15.958 |
| | | Sub-total for items originally identified in 2008 | 2.820 | 11.899 | 14.261 | 12.949 | 13.263 |
| | | Sub-total for items originally identified in 2009 | | 0.613 | 1.645 | 2.092 | 2.002 |
| | | Sub-total for items originally identified in 2010 | | | 0.055 | 0.495 | 0.693 |

CAPITAL ITEMS (Table 3)

| Year Identified | | Description | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|
| 2010 | | Construction, Planning Reporting and Execution Project | | | 4.670 | 7.036 | 4.000 |
| 2008 | | IT Governance/Demand Management | 0.050 | 0.680 | 1.277 | 1.277 | 1.277 |
| 2008 | | Field Work Effectiveness | | 0.482 | 0.900 | 0.900 | 0.900 |
| 2009 | | Major Projects Design Work | | | 2.000 | 0.505 | 0.865 |
| 2009 | | Wireless Voice Modernization Project | | 0.350 | 0.400 | 0.500 | 0.500 |
| 2008 | | Geographic Information System | | | | 0.270 | 0.216 |
| 2008 | | Field Work Effectiveness -- Phase 4 | | | | 0.125 | 0.125 |
| 2010 | | Major Projects - Reorganization | | | 0.075 | 0.075 | 0.100 |
| 2008 | | Review meter change process - lock & walk approach | | | 0.050 | 0.050 | 0.050 |
| 2008 | | Remove local backups - Cap | | 0.020 | 0.020 | 0.020 | 0.020 |
| 2009 | | Meter Shop - Repair vs. replace rotary for rotary meters | | 0.330 | 0.330 | | |
| | Capital Total | | 0.050 | 1.862 | 9.722 | 10.758 | 8.053 |
| | | Sub-total for items originally identified in 2008 | 0.050 | 1.182 | 2.247 | 2.642 | 2.588 |
| | | Sub-total for items originally identified in 2009 | | 0.680 | 2.730 | 1.005 | 1.365 |
| | | Sub-total for items originally identified in 2010 | | | 4.745 | 7.111 | 4.100 |

REVENUE ITEMS (Table 4)

| Year Identified | | Description | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|
| 2009 | | Upstream Transportation Optimization | 4.968 | 14.048 | 11.704 | 22.004 | 14.200 |
| 2008 | | Dawn to Parkway Optimization | | | 3.020 | 3.020 | 1.800 |
| 2008 | | Dawn Dehydration Project | | 0.634 | 0.634 | 0.634 | 0.317 |
| 2008 | | Sales and Marketing Realignment | 0.395 | 0.192 | 0.467 | 0.244 | 0.200 |
| 2008 | | Deliver Ontario Power Authority commercial Conservation Demand Management Programs | | 0.076 | 0.250 | 0.172 | |
| | Revenue Total | | 5.363 | 14.950 | 16.075 | 26.074 | 16.517 |
| | | Sub-total for items originally identified in 2008 | 0.395 | 0.902 | 4.371 | 4.070 | 2.317 |
| | | Sub-total for items originally identified in 2009 | 4.968 | 14.048 | 11.704 | 22.004 | 14.200 |
| | | Sub-total for items originally identified in 2010 | | | | | |

UNION GAS LIMITED

Undertaking of Ms. Li
To Ms. Elliott

Please provide calculation of the 10.3% number.

---

| | ($000's) | | |
|---|---|---|---|
| | Total Company | Unregulated Storage | % |
| Net Book Value of Pre'97 Assets as at December 31, 2006 | 731,284 | 75,451 | 10.3% |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Elliott

Please confirm that when Phantom stock is cashed in and paid out to the employee, that the amount is treated like any other bonus you would pay to the employee and is deductible.

---

The phantom stock paid out is a taxable benefit to the employee. The expense associated with the phantom stock paid out is not deductible for corporate tax purposes.

UNION GAS LIMITED

Undertaking of Ms. Li
To Ms. Elliott

Please disaggregate the 27,496 million.

---

| | ($Millions) |
|---|---|
| Capitalized overheads | $23.075 |
| Disposal costs capitalized | 4.168 |
| Depreciation - Non-deductible costs | 0.292 |
| Deductible costs included in NBV | 0.253 |
| Debt issue costs (tax vs accounting) | (0.332) |
| Total | $27.456 |

UNION GAS LIMITED

Undertaking of Ms. Li
To Ms. Elliott

Please provide calculations for threshold test.

---

The quantitative thresholds for determining operating segments in accordance with CICA 1701 Segment Disclosures are as follows:

Quantitative thresholds

*.19 "An enterprise should disclose separately information about an operating segment that meets any of the following quantitative thresholds:*

- *(a) its reported revenue, including both sales to external customers and intersegment sales or transfers, is 10 percent or more of the combined revenue, internal and external, of all operating segments;*
- *(b) the absolute amount of its reported profit or loss is 10 percent or more of the greater, in absolute amount, of:*
  - *(i) the combined reported profit of all operating segments that did not report a loss; or*
  - *(ii) the combined reported loss of all operating segments that did report a loss; and*
- *(c) its assets are 10 percent or more of the combined assets of all operating segments.*

The only quantitative test that can be performed based on the information available is the revenue test. Union does not prepare internal information on reported profit or total assets for its unregulated operations.

Based on the revenue test, the unregulated operations is 6% of total revenue.

UNION GAS LIMITED

Undertaking of Ms. Li
To Ms. Elliott

Please provide relevant section of USGAAP for utilities.

---

**ASC 980 Regulated Operations**
**Entities**
**15-2** The guidance in the Regulated Operations Topic applies to general-purpose external financial statements of an entity that has regulated operations that meet all of the following criteria:

a) The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

b) The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form. If an entity's regulated rates are based on the costs of a group of entities and the entity is so large in relation to the group of entities that its costs are, in essence, the group's costs, the regulation would meet this criterion for that entity.

c) In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs. This last criterion is not intended as a requirement that the entity earn a fair return on shareholders' investment under all considerations; an entity can earn less than a fair return for many reasons unrelated to the ability to bill and collect rates that will recover allowable costs[1]. For example, mild weather might reduce demand for energy utility services. In that case, rates that were expected to recover an entity's allowable costs might not do so. The resulting decreased earnings do not demonstrate an inability to charge and collect rates that would recover the entity's costs; rather, they demonstrate the uncertainty inherent in estimating weather conditions. This requirement must also be evaluated in light of the circumstances. For example, if the entity has an exclusive franchise to provide regulated services or products in an area and competition from other services or products is minimal, there is usually a reasonable expectation that it will continue to meet the other criteria. Exclusive franchises can be revoked, but they seldom are. If the entity has no exclusive franchise but has made the very large capital investment required to provide either the regulated services or products or an acceptable substitute, future competition also may be unlikely.

[1] Allowable costs – all costs for which revenue is intended to provide recovery. Those costs can be actual or estimated. In that context, allowable costs include interest cost and amounts provided for earnings on shareholders' investments.

UNION GAS LIMITED

Undertaking of Ms. Li
To Ms. Elliott

Please clarify impact to the allocation of regulated versus unregulated.
---------------------------------------------------------------------------------------------------------

Capitalization of overheads for regulatory purposes does not impact the allocation of assets regulated versus unregulated.

Storage asset additions are classified into 4 basic categories and their allocation of regulated versus unregulated is determined as follows:

| Description | Allocation Methodology |
|---|---|
| New Storage Asset – increase in capacity or deliverability | 100% Allocation to unregulated |
| New Storage Asset – no increase in capacity or deliverability | Allocated regulated versus unregulated based on the historic allocation of assets at that location |
| Replacement Asset – no increase in capacity or deliverability | Allocated regulated versus unregulated based on the historic allocation of assets being replaced. |
| Replacement Asset – increase in capacity or deliverability | Cost of replacing the existing asset like for like is allocated regulated versus unregulated based on the historic allocation of assets being replaced. The cost of providing the incremental capacity or deliverability is allocated 100% to the unregulated operation. This results in a new blended rate for this asset. |

UNION GAS LIMITED

Undertaking of Mr. Viraney
To Ms. Cummings

Please advise number of potential conversion customers in Red Lake.

---

Conversion customers forecasted for the Red Lake project include 1,071 residential and 182 commercial customers over a 10 year period.

UNION GAS LIMITED

Undertaking of Mr. Viraney
To Ms. Cummings

Please advise whether Union intends to adopt any or all of the recommendations outlined in "Asset Management Strategy Assessment" by Vesta Partner provided as IR No. J.B-4-1-13, Attachment 1.

---

Union has not determined the extent to which it will or will not adopt the recommendations outlined in the Vesta Partners' report.

UNION GAS LIMITED

Undertaking of Mr. Viraney
To Ms. Cummings

Please advise the number of planners at Union; to comment on assessment of Union's succession planning.

---

The section under the "Training & Competency" heading in Vesta Partner's report (page 28) refers only to STO (Storage & Transmission Operations) planners. Union currently does not have any dedicated planners within STO. This function is performed primarily by Managers. The recommendation to have a dedicated planning function, including training for that role, will be considered in Union's Asset Management Strategy development**.**

The comment "that proper succession planning is also inadequate" on page 28 was made specifically in reference to Construction & Growth ("C&G"). Union does not agree with Vesta's observation. Succession planning for C&G roles is included within the Distribution Operations succession planning exercise and is effective.

UNION GAS LIMITED

Undertaking of Mr. Viraney
To Ms. Cummings

Please explain $5.6 million adjustment in Exhibit J.O-4-15-1.

---

| | ($Millions) |
|---|---|
| CDN GAAP Pension Amortization | 4.4 |
| Payroll Accrual (S&W & Benefits) | 0.8 |
| HST Deferral | 0.5 |
| Other | (0.1) |
| Total | 5.6 |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Gardiner

Notwithstanding what could occur, to calculate unauthorized overrun penalties that could accrue for the amount of space and deliverability overruns in the Non-utility Business in October of 2011.

---

As indicated in Union's MPSS Rate Schedule, from the period of August 1 to December 15, the penalty charge for exceeding the storage balance is \$60/GJ. Union's excess in October 2011 was 1.6 PJ. The penalty would be \$96 million.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Line 3**

Union states that the non-utility storage plant allocation factor for the Dawn Plant J project should be 42.5% because (a) it is a storage and transmission asset, and (b) the project created incremental capacity.

Please show in detail how the 42.5% allocation factor was calculated.

Identify the costs that were allocated and the costs that were direct assigned, with an explanation for each.

Please provide the resulting increase in working capacity and deliverability for each storage pool.

---

The cost of replacing Dawn Plant A in the existing location with engines that provide the same horsepower was allocated based on the original Dawn Plant A allocation. The cost of changing locations and increasing the engine to provide incremental horsepower was charged 100% to the unregulated operation, which resulted in a new blended rate for this facility.

Dawn Plant J is a compressor plant that was constructed to replace the existing horsepower at Dawn Plant A which was decommissioned to meet the requirements of our Comprehensive Certificate of Approval Program. This project did not increase the working capacity or deliverability of individual storage pools.

Dawn Plant J
Blended Allocation to Unregulated Storage

| | Millions | Regulated | Unregulated |
|---|---|---|---|
| Dawn A Plant - Current Allocation | | 80.14% | 19.86% |
| Cost of replacing existing | $ 29.9 | $ 24.0 | $ 5.9 |
| Revenue Generating | $ 11.8 | | $ 11.8 |
| | $ 41.7 | $ 24.0 | $ 17.7 |
| New Blended % for Dawn A / J | | 57.55% | 42.45% |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Line 3**

Please provide additional detail on Line No.144 including the type of infrastructure and its role in creating the additional services? Are these types of services also provided by the non-utility business?

---

The project referenced at Line No. 144 is ESPM (NGEIR). As part of the NGEIR process, Union committed to offer four new ex-franchise power services. To accommodate these new services, IT application system changes were necessary. One of the major changes was the requirement to provide additional nomination windows for power producers.

Of the four new services, three are non-utility storage or storage-related services – F24S, UPBS and DPBS. One service is provided by the regulated business – F24-T.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Line 3**

Please provide additional detail on Line No. 146 including the type of infrastructure and its role in meeting emerging demands? How are those demands not met?

---

The project description on line 144 should read "IT Demand Management" and not "IT Demand Management Bus. Dev. and S&T". The projects submitted in the past have almost entirely supported the regulated business. The phrase "emerging demands" refers to the internal demand for capital.

The Demand Management process is an approval process generally for smaller IT application projects submitted to the IT department throughout the year by various Union Gas business leaders. Identifying specific IT projects closer to the time of undertaking the project allows for more accurate costing and benefits analysis and appropriate prioritization relative to the other IT opportunities that exist at the time. An example is the Corrosion System Upgrade implemented in 2011.

For a more complete description of this process please refer to Exhibit B1 Tab 7 page 2 lines 8 and following.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Line 13**

Please describe the improved injection and withdrawal capacity that will result from the Mandaumin Pool Modifications project.

Provide the working capacity and design deliverability for this pool before and after the project. Union's proposed cost allocation methodology states that if a project "improves efficiency or provides growth opportunities for the unregulated business, then the incremental cost of the project beyond the simple replacement is directly assigned to unregulated storage."(EB-2010-0039, Exhibit A, Tab 4, p. 14) Please explain why a direct allocation to non-utility storage is not necessary for this project.

---

The working capacity and design deliverability for this pool will not change with the proposed Mandaumin Pool modifications.

The Mandaumin pool currently has excess water content in the gas during withdrawal. Due to these water content issues, Union has had operational issues in withdrawing the full working inventory of the pool. The new facilities will provide the operational capability to assist in ensuring that no gas will be trapped in the pool.

The costs to increase the operational efficiency of the pool are allocated in proportion to the existing asset allocation because there is no incremental capability that requires a direct allocation to non-utility storage. The existing allocation assumes the full working capacity is available.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Line 19**

Will Union need to install emergency shut down valves on any storage injection/withdrawal wells that were put into service since the NGEIR Decision?

Please provide a table showing, for each Union storage pool, the number of storage/injection wells in operation as of 12/31/2006, 12/31/2011, and 12/31/2012 (forecast).

---

Union will install emergency shutdown valves in pools that contain wells with the highest risk consequence ratings. This may include wells that were put into service since the NGEIR Decision.

| **Pool** | **31-Dec-06** | **31-Dec-11** | **31-Dec-12** |
|---|---|---|---|
| Dawn 59-85 | 7 | 9 | 9 |
| Dawn 47-49 | 16 | 16 | 16 |
| Payne | 11 | 10 | 10 |
| Dawn 156 | 18 | 22 | 22 |
| Waubuno | 7 | 7 | 7 |
| Bickford | 5 | 5 | 5 |
| Terminus | 8 | 8 | 8 |
| Bentpath | 7 | 7 | 7 |
| Rosedale | 5 | 5 | 5 |
| Dawn 167 | 11 | 11 | 11 |
| Enniskillen 28 | 8 | 8 | 8 |
| Sombra | 10 | 10 | 10 |
| Oil Springs East | 6 | 6 | 6 |
| Dow 'A' | 6 | 6 | 6 |
| Edys Mills | 5 | 5 | 5 |
| Bentpath East | 4 | 4 | 4 |
| Booth Creek | 2 | 2 | 2 |
| Mandaumin | 5 | 5 | 5 |
| Oil City | 2 | 2 | 2 |
| Bluewater | 2 | 2 | 2 |
| Heritage | 0 | 1 | 1 |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Lines 142-147**

Using the same methodology shown in EB-2010-0039, Exhibit A, Tab 4, Page 13, please calculate the General Plant Excluding Vehicles Allocation Factor for each year from 2008 through 2013 using the actual or forecast data applicable to that year.

---

Please see the Attachment for the General Plant Allocator Excluding Vehicles for 2007 through 2013. Union did not revise the General Plant allocators between 2007 and 2013.

**General Plant Allocators**
(using KPMG allocation methodology)

| General Plant Allocator | 2007 (KPMG Allocation) Based on Year End December 31, 2007 | 2008 (KPMG Allocation) Based on Year End December 31, 2007 | 2009 Based on Year End December 31, 2008 | 2010 Based on Year End December 31, 2009 | 2011 Based on Year End December 31, 2010 | 2012 Based on Year End December 31, 2011 | 2013 Based on Forecasted Year End December 31, 2012 |
|---|---|---|---|---|---|---|---|
| Total Plant (Dec 31 - excluding WIP, ARO, and General Plant) | 5,198,765,878 | 5,198,765,878 | 5,567,550,810 | 5,834,404,334 | 5,977,799,172 | 6,227,537,421 | 6,363,370,000 |
| Total Unregulated Storage (Dec 31 - excluding WIP, ARO and General Pl | 172,571,936 | 172,571,936 | 221,806,815 | 303,485,699 | 305,645,489 | 323,112,433 | 322,528,000 |
| % Unregulated Storage to Total Plant | 3.32% | 3.32% | 3.98% | 5.20% | 5.11% | 5.19% | 5.07% |
| O&M Storage Support Allocator | 2.52% | 2.52% | 2.52% | 2.52% | 2.90% | 2.90% | 2.90% |
| **General Plant Allocation Factor** | **2.92%** | **2.92%** | **3.25%** | **3.86%** | **4.01%** | **4.04%** | **3.98%** |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

**Ref: J.B-8-10-2, Attachment 1, Lines 142-147**

Please confirm that the ex-franchise services referred to are the F24-T, F24-S, UPBS, and DPBS services, and that except for F24-T, these services are non-utility storage services.

Please identify the portion of the $1.932 million of capital cost that Union proposes to include in rate base that is associated with the non-utility storage service and the portion of the cost is related to F24-T.

What this capital expenditure included in the 2007 budget that was approved in the 2007 rate case?

Please confirm that Union has been charging a rate for F24-T service that is designed to recover the incremental costs of providing this service.

Please provide the revenue Union has collected each year for F24-T service from 2007 to the present.

---

Union's ex-franchise power services that were developed from the NGEIR review process include 3 unregulated (non-utility) storage or storage-related services – F24S, UPBS & DPBS - and 1 regulated service – F24-T.

The asset associated with the $1.932 million of capital for the ESPM project in 2007 is fully amortized and has no impact on the 2013 rate base.

The ESPM project was not included in the 2007 budget that was proposed in the 2007 rate case. This project was created in response to the NGEIR settlement agreement dated June 13, 2006, which was subsequent to the settlement agreement of the 2007 rate case, EB-2005-0520, on May 15, 2006.

Confirmed.

UNION GAS LIMITED
Summary F24-T Revenue
Year Ending December 31

| Line No. | Particulars ($000's) | Actual 2007 (a) | Actual 2008 (b) | Actual 2009 (c) | Actual 2010 (d) | Actual 2011 (e) | Actual YTD 2012 (f) |
|---|---|---|---|---|---|---|---|
| 1 | F24-T Service | - | 680 | 2,634 | 2,969 | 2,935 | 733 |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Elliott

Please confirm basis for cost allocation.

---

O&M for storage related assets is allocated based on the allocation of the underlying assets. The underlying asset is allocated based on gross capital cost. The chart below illustrates how the capital assets associated with a storage facility are allocated.

| Description | Total Asset Value | Regulated | | Unregulated | |
|---|---|---|---|---|---|
| Underground Storage Well | 10,000,000 | 62.34% | 6,234,000 | 37.66% | 3,766,000 |
| Additional Wells at existing location | 6,000,000 | 0.00% | 0 | 100.00% | 6,000,000 |
| Total Asset value post construction | 16,000,000 | | 6,234,000 | | 9,766,000 |
| Revised Allocation | | | 38.96% | | 61.04% |

The O&M associated with this facility would be allocated 38.96% to the regulated operation and 61.04% to the unregulated operation.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please attempt to disaggregate "Service Contractors" line.

---

| Particulars ($ Millions) | | |
|---|---|---|
| Integrity | 6.5 | (Exhibit J.D-1-2-6 e)) |
| Line Locates | 3.9 | (Exhibit J.D-1-2-6 e)) |
| Customer Care Costs | 3.5 | (2007 Board Filed $16.841 million vs. 2013 $20.329) |
| Other | 0.1 | |
| Total | 14.0 | |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please confirm that all five member-specific project investments were done internally at Union as part of the utility.

---

The five projects referenced in Appendix B of the ETIC Business Plan dated December 15, 2011 are projects that Union is interested in pursuing through ETIC. None of the projects have been initiated by Union or ETIC.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please confirm whether ETIC is reimbursing for Union staff time on ETIC work; to give a projection of costs for test year.

---

Union staff who work on ETIC projects are not reimbursed by ETIC.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please confirm how many ETIC deliverables are done and how many are in progress.

---

Union has confirmed that the first two and the last of the list of ten deliverables on the "Virtual Organization" are completed. The remaining deliverables on this list are at various stages of development but are not yet completed. For example, the launch of the first round of projects was completed in early 2012 and LDC approval received. However there are other 2012 ETIC projects that are still being finalized and consequently LDC approvals have not been received for this next tranche of 2012 projects.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please provide a breakdown of all amounts expected to be paid by ETIK to CGA for any services being provided by CGA, whether from Third Parties or from CGA internally.

---

ETIC's annual operating budget is $350,000 per year and Union's annual commitment to this operating budget is $69,650 as indicated at Exhibit J.D-7-3-1. ETIC's annual budget is provided below. Services that CGA are being provided on a cost recovery basis to ETIC are indicated below:

| Line No. | Expense | ($000's) | |
|---|---|---|---|
| 1 | Executive | 100.0 | |
| 2 | Support Staff | 30.0 | CGA |
| 3 | Government Relations | 24.0 | CGA |
| 4 | Technical | 25.0 | |
| 5 | Financial | 60.0 | |
| 6 | Rent | 18.0 | CGA |
| 7 | Travel | 36.0 | |
| 8 | Marketing/ Communication | 20.0 | |
| 9 | IT Support and Hardware | 10.0 | |
| 10 | Legal | 20.0 | |
| 11 | Miscellaneous | 7.0 | |
| 12 | Total | 350.0 | |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

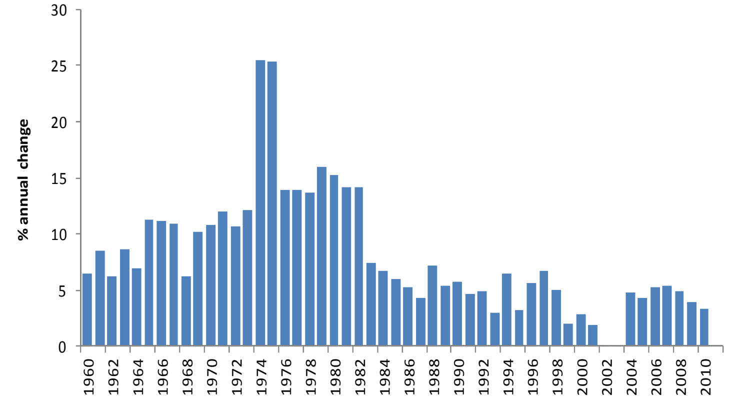
Please provide regulatory ask paper.

---

Attached is a copy of the “Regulatory Ask” draft that was identified in the ETIC Business Plan. This draft was a “work in progress” and has not been finalized by ETIC.

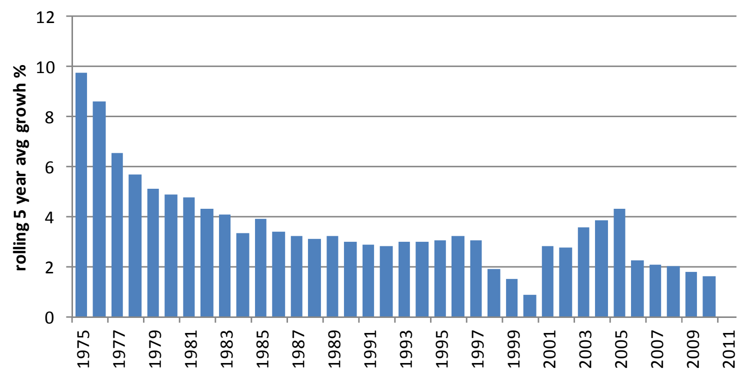
Canada's national natural gas distribution system is entering a period of increased renewal. Originally put in place over the 1960's and 1970's (see Figure 1) an increasing proportion of Canada's natural gas grid is now approaching the end of its designed lifespan. This means an increase in the annual quantities of pipes, fittings and fixtures that will need to be replaced.

**Figure 1: Growth in Year-end Gross Capital Stock, net of buildings**




Source: Statistics Canada #031-0002

**Figure 2: Growth in Natural Gas Customer Base**




Source: Statistics Canada 129-0003

The current system was originally built at a time when customer bases were growing more rapidly (see Figure 2), were easier to attached, and vast undeveloped energy from both hydrocarbon and hydraulic sources were available to meet growing demand. But fast forward forty years and we find that, while Canada still has abundant natural gas resources, there is no longer a large and fast growing "yet to be attached" customer base and renewing the existing systems means working in the very heart of the Canadian urban and sub-urban landscape.

But this renewal affords the opportunity for Canada's natural gas LDC's to take advantage of forty years of innovation in energy system and energy end use design to infuse their systems and consumers homes and businesses with new innovations and technologies that will create a more integrated, efficient, clean, and more affordable energy system

For Canada's regulated natural gas utilities pushing new technology is something of a reversal. Since the days of "unbundling" Canada's regulated natural gas monopolies LDCs have been limited in the research and development spending that they could recover in rates. But by pooling their collective technology and innovation spending resources LDCs can leverage ratepayer funding with shareholder and government monies to the collective benefits of energy consumers across Canada.

Certainly cleaner and more efficient energy services will have broad public benefits including lower GHG and other emissions. But the questions remain ...
Why should LDC monopolies be moving into technology development and deployment? And,
Why should LDC ratepayers foot the technology and innovation bill?

The answer follows.

**1. LDC's provide an existing connection and relationship to millions of Canadian energy consumers**

**Figure 3: Natural Gas LDC Franchise Areas**


Natural gas is used in virtually every region of Canada. Natural gas utility franchise areas cover the country from coast to coast to coast (see Figure 3) delivering safe, clean, versatile, affordable natural gas energy to over 20 million Canadian in over 6.3 million homes, businesses, schools, and other institutions. Natural gas meets over 30 percent of Canada's energy needs making it the second more used energy form in Canada, after refined petroleum products.

This comprehensive relationship with Canada's energy consumers highlights the value in having natural gas distribution utilities play a key role in the development and deployment of new energy technologies. Technologies brought forth by the LDC will reach more consumers more quickly and be able to deliver the economic, environmental and societal benefits more quickly and more comprehensively than any new enterprise.

**2. LDCS's undergo regular regulatory oversight and review**

Canadian natural gas utilities have decades of operational excellence under the watchful eye of both economic and operational regulatory authorities. Any major action taken by a natural gas utility, anywhere in Canada goes through an extensive regulatory review process. This existing oversight would be brought to bear on any monies used for innovation and technology support.

This degree of governance provides customer protection and allows any concerned party to appear before the appropriate regulatory authority to express their view, submit expert opinion, and supporting information to test the claims and actions and expenditures of the utility. Indeed it is commonplace for Canadian natural gas utilities to face such regular scrutiny and these regulatory review processes have well established methods and rules that are backed by the force of law.

**3. LDCs are energy system program finance and business risk experts**

Allowing well financed and stable LDC to initiate technology and innovation programs helps limit the program's risk. LDCs participation will leverage ratepayer's investment helping to mitigate any business and financial risks associated with new technologies and innovations. LDCs financial expertise can further limit potential cost consequences to the public. LDC participation will allow development and deployment of a number of innovations and new technologies that might not otherwise be viable. Once established and successful, these innovations could remain under LDC control or be turned back to private sector markets and operators.

## 4. LDCs have extensive energy service & system operational expertise

LDCs employ a highly skilled workforce, directly employing tens of thousands of energy systems experts in the form of engineers, gas fitters, and natural gas technicians' and others. Canadian natural gas LDCs have provided billions of hours of safe and reliable natural gas energy services to Canadians.

This expertise makes natural gas systems and their LDC franchise operators the ideal venues for the "real world" development and delivery of new, beneficial energy end use technologies. LDC's, through cooperative joint efforts, can bring new energy end use technologies into operation more quickly and safely than any other energy market player.

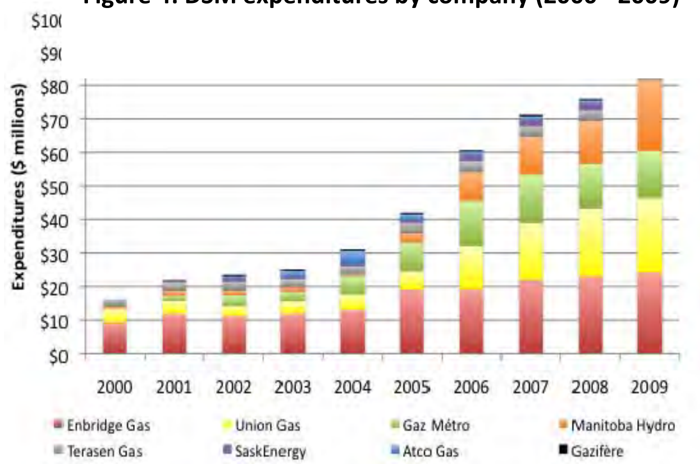
By letting LDCs return to technology research, development, and deployment they can pool their energy systems expertise and leverage their collective efforts to provide the maximum benefits available from the deployment of new energy systems and services.

## 5. LDCs have a history of success operating rate payer supported programs

Canada's natural gas LDC's have shown they are innovative and, when allowed, are willing and able to make appropriate investments in cleaner, more productive energy systems and technologies.

For example from 2000 through 2009, more than 459 million dollars were invested in demand side management conservation (DSM) activities by natural gas utilities in Canada, saving almost 1.8 billion cubic metres of natural gas [1] (see Figure 4).

**Figure 4: DSM expenditures by company (2000 - 2009)[1]**




LDCs, regulators and consumer groups have evolved a model for such programs that allows the interests of all parties to be reflected and protected. Recreating a similar mechanism outside the regulated utility model would be unnecessarily costly and duplicative. DSM programs are but one example of the history of success that Canada's natural gas LDC's have in bringing new and innovative ideas to fruition within the regulated utility business model.

[1] Canadian Natural Gas DSM Activities 2000-2009, IndEco Research,

**CONCLUSIONS AND SUMMATION**

Canada's natural gas LDCs are key investors in the Canadian energy marketplace. Their existing investments, financial and operational expertise, and connection to over 20 million Canadians in over 6 million homes, businesses, industries, and institutions make them an ideal interlocutor to advance energy innovation and technology in Canada.

The consumer protection afforded by the existing regulatory oversight framework will provide the due diligence to monitor and ensure that ratepayers benefit from LDC investments in innovation and technology and that these investments are both prudent and well planned.

In short, Canadian natural gas utilities' 100 plus years of energy service system construction and safe operation make them the most logical partner to bring innovation and technological advancements safely into the existing energy services system in Canada. Doing so will lead to a more efficient, cleaner integrated energy services system.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Cummings

Please provide details of the integrated community energy systems project.

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Integrated Community Energy Systems have been identified as an ETIC technology area of interest. Specific projects related to this technology area have not yet been finalized by ETIC except for the thermal metering project specified by Union in its response at Exhibit J.D-7-5-1 which includes a Union investment. Other specific project that are developed as a part of this focus area will be invested in by Union only if they relate to Union business. If they are Spectra related than they will not be invested in by Union.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Ms. Elliott

Please consider filing the unredacted Towers Perrin Report.

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Union is not prepared to provide an unredacted copy of the Towers Perrin Report. The information redacted from the report does not pertain to Union Gas.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Broeders

Please confirm number of consumer advocate clients of Union's Witness Mr. Fetter.

---

Of the four clients listed in Mr. Fetter's response to J.E-2-15-4 part c), two are consumer advocates and two are commissions. Mr. Fetter also confirmed that these are all of his consumer advocate clients.

UNION GAS LIMITED

Undertaking of Ms. Girvan
To Ms. Cummings

Please make an inquiry regarding Enbridge's ETIC Contribution Plans.

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Union has inquired about Enbridge's ETIC contribution and Enbridge has not responded.

UNION GAS LIMITED

Undertaking of Ms. Girvan
To Ms. Cummings

Please reconcile the difference in pension and benefits on page 28 and page 3.

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The evidence at Exhibit A2, Tab 1, Sch 1 was not updated as part of the March update. Page 28 refers to the original D1, Tab 2 evidence not the updated evidence.

UNION GAS LIMITED

Undertaking of Mr. Wightman
To Ms. Cummings

Please provide the number eligible for LTIP from 2007 to 2011.
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The number of positions eligible for LTIP varied between 27 and 32 from 2007 to 2012.

UNION GAS LIMITED

Undertaking of Mr. Wightman
To Ms. Cummings

Please advise on engineering work done in-house versus outside.

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The majority of Union's engineering design work is completed in-house, compared to outside.

However, for larger more complex storage and transmission projects such as compressor station installations or specialty engineering (i.e. geotechnical investigation, complex environmental assessments, electrical interference, etc.) Union would utilize external consultants to complete the detailed design work. In these circumstances however, Union still provides expert oversight and guidance to the consultants to ensure the work complies with all applicable technical standards and Union's operating requirements.

The majority of Union's construction work is completed by outside contractors. Again, this work is inspected by Union personnel to ensure the work meets Union's specifications, technical requirements and that the appropriate safety precautions are adhered to at all times.

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Broeders

Please confirm if Union accepts that its financial and business risk have either remained unchanged or have declined since last analyzed by Dr. Carpenter of the Brattle Group.

---

Union has not analyzed it business and financial risks, but accepts that its overall risk profile has not materially changed 2004. Dr. Carpenter's evidence was part of the evidence filed by the Brattle Group in EB-2005-0520. Written evidence was also prepared by Dr. Kolbe and Dr. Vilbert.

The Brattle Group's evidence is attached as Attachments 1, 2 and 3. It was the Brattle Group's opinion that the appropriate deemed equity level for Union ranged between 40% and 56% depending upon the allowed return on equity.

# WRITTEN EVIDENCE
# OF
# A. LAWRENCE KOLBE
# FOR
# UNION GAS LIMITED

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

January 2006

WRITTEN EVIDENCE OF
A. LAWRENCE KOLBE

**Table of Contents**

WRITTEN EVIDENCE OF
A. LAWRENCE KOLBE

## I. INTRODUCTION AND SUMMARY

**Q1. Please state your name and address for the record.**

A1. My name is A. Lawrence Kolbe. My business address is The Brattle Group, 44 Brattle Street, Cambridge, Massachusetts, 02138.

**Q2. Please summarize your background and experience.**

A2. I am a Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco and Brussels. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. from the Massachusetts Institute of Technology, both in economics.

**Q3. Please review any parts of your background and experience that are particularly relevant to your evidence in this proceeding.**

A3. I have been a student of rate regulation for over 25 years. Among other publications, I am a co-author of two books[1] and dozens of papers and articles that focus on various aspects of rate regulation, as well as a third book that addresses capital investment and valuation generally.[2] One of my papers appears in a law journal and addresses the economics of the

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[1] A. Lawrence Kolbe and James A. Read, Jr., with George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Cambridge, MA: The MIT Press (1984), and A. Lawrence Kolbe, William B. Tye and Stewart C. Myers, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Boston: Kluwer Academic Publishers (1993).

[2] Richard A. Brealey and Stewart C. Myers, with The Brattle Group, *Capital Investment and Valuation* (Brattle author A. Lawrence Kolbe), New York: McGraw-Hill/Irwin (2003).

U.S. Supreme Court's risk-return standards for rate-regulated companies,[3] and other papers in various economics journals address aspects of the same set of issues.[4]

I have testified on financial and regulatory issues in many forums. These include international arbitrations in The Hague, London and Melbourne, Australia; lawsuits in U.S. courts; U.S. arbitrations, and Canadian and U.S. regulatory proceedings. In particular, I have provided expert testimony in regulatory proceedings before seven Canadian and U.S. federal regulatory bodies and one or more regulatory bodies in 18 provinces or states (although I have not previously appeared before the Ontario Energy Board -- "Board"). These proceedings have concerned a wide variety of rate-regulated companies or industries, including gas distribution and gas transmission companies. Appendix A contains more information on my professional qualifications.

**Q4. What is the purpose of your evidence in this proceeding?**

A4. Brattle has been asked by Union Gas Limited ("Union," or the "Company") to identify the deemed capital structure that provides a fair dollar return on equity for the Company's gas operations under the jurisdiction of the Board. To accomplish this task, three Brattle Principals, Dr. Paul R. Carpenter, Dr. Michael J. Vilbert and myself, supply evidence in this proceeding.

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3 A. Lawrence Kolbe and William B. Tye, "The *Duquesne* Opinion: How Much '*Hope*' Is There for Investors in Regulated Firms?" *Yale Journal on Regulation* 8:113-157 (1991).

4 A. Lawrence Kolbe and William B. Tye, "The Fair Allowed Rate of Return with Regulatory Risk," *Research in Law and Economics* 15:129-169 (1992); A. Lawrence Kolbe and William B. Tye, "Compensation for the Risk of Stranded Costs," *Energy Policy* 24:1025-1050 (1996); and A. Lawrence Kolbe and Lynda S. Borucki, "The Impact of Stranded-Cost Risk on Required Rates of Return for Electric Utilities: Theory and An Example," *Journal of Regulatory Economics* 13:255-275 (1998).

**Q5. Please summarize how the three pieces of evidence relate to one another.**

A5. This evidence (i.e., the **Written Evidence of A. Lawrence Kolbe**) provides Brattle's recommendations for Union's deemed equity ratio. These recommendations are based on economic risk-reward principles explained in this evidence and on information supplied in the evidence of my colleagues, in addition to my own analysis and experience.

In particular, the **Written Evidence of Paul R. Carpenter** analyzes Union's risks, both relative to those of other regulated natural gas companies and relative to Union's risks in the past, from the perspective of an expert in both natural gas markets and rate regulation. Union's operations are primarily gas distribution, but include a material investment in gas transmission and storage as well. Dr. Carpenter's evidence serves two purposes. First, it provides a directional benchmark for Union's appropriate deemed equity ratio relative to that the Company has had in the recent past. Second, it provides information on Union's relative risk. In particular, Dr. Carpenter concludes that Union is riskier today than it was in the past, and that the Company is riskier than a sample of companies in the gas distribution business used by Dr. Vilbert.

The **Written Evidence of Michael J. Vilbert** analyzes the risks, required returns and capital structures of publicly traded companies. Unfortunately, no sample of publicly traded companies just like Union exists. Dr. Vilbert therefore analyzes two benchmark samples that provide information on Union's return requirements. One sample is a set of Canadian rate-regulated companies in several different energy-related businesses. The other sample is a set of U.S. natural gas local distribution companies ("LDCs"). As Dr. Vilbert explains, the Canadian sample alone is too heterogeneous and has too many data problems to serve as the sole benchmark for Union. However, to make the results of his

LDC sample comparable and relevant to Union, he uses Canadian capital market benchmarks (e.g., for the market risk premium) rather than U.S. benchmarks.

Dr. Vilbert relies on principles explained in my own testimony (summarized immediately below) to derive the equity ratios his sample companies would have had if their measured expected rate of return on equity had been equal to the Board's formula rate of return on equity. He examines two possible values for this rate of return, 9.63 percent (based on the Board's formula for the equity rate of return for Union as of 2005) and 8.89 percent (the corresponding value for 2006). We understand that the actual formula value for the rates that are the subject of this proceeding will not be known until near the end of 2006, and one reason for considering two different rates of return on equity is to show how the procedures we use can be adapted to the actual rate of return on equity that will be used.

Dr. Vilbert concludes that at the 9.63 percent rate of return on equity, the LDC sample using Canadian benchmarks would have had an equity ratio of 46 percent, with a range between 42 and 50 percent. The Canadian sample would have had an equity ratio of 44 percent, with a range from 40 to 48 percent. At the 8.89 percent rate of return on equity, the LDC sample would have had a 52 percent equity ratio and the Canadian sample a 50 percent equity ratio, both again with ranges of four percentage points on either side.

**Q6. Please summarize the conclusions in your own evidence.**

A6. My evidence reaches conclusions regarding (1) the implications for rate regulation of the interaction between a company's capital structure and its required rate of return on equity, and (2) Union's required equity ratio.

**Interaction Between Equity Ratio and the Required Rate of Return on Equity:** I understand that the allowed rate of return on equity ("ROE") is determined by the Board's ROE formula. The deemed equity ratio that goes with that value must produce a fair return overall, given Union's overall business risk.

One way to test whether a given equity ratio satisfies that condition is to examine evidence from samples of publicly traded companies. Suppose a sample of companies were of exactly comparable risk to a particular regulated company, and suppose the sample's average estimated required rate of return on equity matched the Board's formula rate of return on equity precisely. Then the deemed equity ratio for the company should equal the market-value capital structure of the sample. Anything else produces an inconsistent outcome, because the expected rate of return of the regulated company will not correspond to the expected rate of return of the comparable-risk sample companies. (Of course, this deemed equity ratio, while derived from market-value data, is combined with the Board's formula rate of return and applied to the regulated company's book-value rate base.)

It would be a coincidence to find that a sample of comparable risk companies just happened to have a required rate of return on equity that exactly matched the current value from the Board's formula, as postulated above. Fortunately, quantitative information about the appropriate deemed equity ratio can still be determined even if the required rate of return on equity of a sample does not precisely match the rate of return on equity from the Board's formula. The sample's capital structure can reliably be restated to the value it would have had if its estimated required rate of return on equity had been precisely equal to the 9.63 or 8.89 percent formula value. That gives the deemed equity ratio that goes with the Board's formula, if the sample's business risk matches that of Union.

To assess accurately evidence on what deemed equity ratio corresponds to the Board's formula, an analyst needs to recognize and incorporate the interaction in public capital markets between the equity ratio and the required rate of return on equity, as Dr. Vilbert's evidence does. It is just as wrong to ignore the interaction between capital structure and the required rate of return on equity as it would be for a life insurance company to ignore the interaction between age and life expectancy. Moreover, just as the interaction between age and life expectancy can be quantified, so too can the interaction between capital structure and the required rate of return on equity. In particular, we lack an agreed theory of how to find "the" minimum-cost capital structure, in part *because* the empirical research is inconsistent with the view that there is a narrow range of optimal capital structures. Fortunately, that fact tells us a great deal about how the required rate of return on equity and the equity ratio interact.

This approach permits a quantitative, not merely a qualitative, approach to selection of a deemed capital structure. In this evidence, I show explicitly how the Board can test quantitatively the internal consistency of sample risk-return evidence and the deemed equity ratio, given the current formula value for the rate of return on equity. I apply this method to my own analysis of the deemed equity ratio.

**Conclusions for Union:** As noted above, my conclusions regarding Union's deemed equity ratio consider Dr. Carpenter's risk evidence and Dr. Vilbert's capital structure analyses for benchmark sample companies, as well as my own experience in risk-return analysis. In my opinion, the deemed equity ratio that is economically consistent with the evidence on the Company's business risk and a 9.63 percent return on equity is in the upper half of a range from 40 to 50 percent. The corresponding economically consistent deemed equity ratio at a 8.89 percent return on equity is in the upper half of a range from 46 to 56 percent.

How do I reach these conclusions? First, as noted, Dr. Carpenter concludes that Union's business risk has recently increased and that Union is more risky than Dr. Vilbert's LDC sample. In my judgment, the LDC sample using Canadian benchmarks provides the best available evidence for the current cost of capital of a pure play, low-risk rate-regulated business in Canada. Nonetheless, Dr. Vilbert has developed procedures to obtain much more reliable Canadian sample estimates than have been available in recent years. For this reason, the Canadian sample deserves some weight in my analysis despite the problems that Dr. Vilbert describes with the sample.

The risk-return evidence for a sample of companies cannot be interpreted precisely with the current state of the art. For that reason, Dr. Vilbert and I specify ranges of values for the deemed equity ratio, not a single point estimate. Based on Dr. Carpenter's evidence and my own experience, I believe Union's deemed equity ratio should be higher than those of Dr. Vilbert's samples, but it is difficult to say by precisely how much. At a 9.63 percent rate of return on equity, I therefore adopt the outside values of Dr. Vilbert's two samples as the relevant range for Union's deemed equity ratio, i.e., 40 to 50 percent.[5] However, based on Union's relative risk, I believe that the Board should allow a value in the upper

[5] As explained in Dr. Vilbert's evidence, the range is based in part on the achievable level of accuracy in cost of capital estimation with the current state of the art. See also my footnote 19, below.

half of that range. I reach the corresponding conclusion at the 8.89 percent return on equity, i.e., that the evidence implies that Union's deemed equity ratio should be in the upper half of an equity ratio range of 46 to 56 percent.

**Q7. How is the remainder of your evidence organized?**

A7. *Section II* describes the interaction between the equity ratio and the cost of equity.[6] *Section III* discusses the evidence on the equity ratios of available benchmark groups at the Board's formula rate of return on equity and on Union's overall risk. It then presents my conclusions on the deemed equity ratio that produces an economically appropriate return for Union at the alternative values for the Board's formula rate of return on equity. Appendix B provides more detail on the interaction between capital structure and the cost of equity.

## II. COST OF EQUITY AND CAPITAL STRUCTURE

**Q8. Why do you address the topic of the cost of equity and capital structure?**

A8. I understand the Board to arrive at a dollar return on equity by applying the approved rate of return on common equity to the deemed level of common equity in a regulated company's capital structure. Therefore, my evidence analyzes how the Board can pick a deemed equity ratio that will produce a fair dollar return on equity, taking either the 9.63

[6] Dr. Vilbert and I use the phrase, "cost of equity" in the finance textbook sense, to refer to the expected rate of return in capital markets that is available on alternative investments of equivalent risk to the equity in question.

percent or the 8.89 percent equity rate of return as fixed. Modern financial economics can provide considerable insight on this issue.

In particular, financial economics teaches that the cost of equity varies not just with business risk, but also with financial risk, which in turn depends on the equity ratio. That unbreakable link complicates the identification of the right deemed equity ratio, given a rate of return on equity.

**Q9. Why do you say that the "unbreakable" link between the cost of equity and capital structure complicates the selection of the right deemed equity ratio?**

A9. Since a company's cost of equity depends in part on its capital structure, a change in capital structure changes its cost of equity. For example, suppose a sample of companies and the regulated company in question had identical business risk. Then their overall expected returns should be the same (differences in embedded interest costs aside). If the sample's cost of equity were equal to the Board's formula return on equity, then the sample's (market-value) equity ratio would equal the appropriate deemed equity ratio, and the analysis would be complete.

However, in general the sample's cost of equity will not equal the formula cost of equity. Therefore, a way must be found to determine the appropriate deemed equity ratio at the formula cost of equity. This section explains how to accomplish this task.

**Q10. How is the discussion organized?**

A10. This section first explains the interaction between the risk of equity and the equity ratio, and in particular why debt magnifies the risk of equity, using an everyday example.[7] The section then shows how regulation can determine the appropriate equity ratio from sample risk-return evidence. This discussion relies on an extensive body of financial research, summarized in Appendix B.[8]

### A. THE RISK-MAGNIFYING EFFECTS OF DEBT: AN EVERYDAY EXAMPLE

**Q11. Why does more debt mean more risk for equityholders?**

A11. Debt magnifies the variability of the equity return. Consider a simple example. Suppose a couple takes money out of their savings and buys a dwelling for $100,000. The dwelling's future value is uncertain. If housing prices go up, they win. If housing prices go down, they lose. Figure 1 depicts the outcome of a 10 percent fluctuation in the dwelling's price.[9]

---

7 Preferred equity acts much like debt in magnifying common equity's risk. However, it simplifies the discussion to focus on debt and common equity alone.

8 A focus on how capital structure affects the value of the firm and the firm's cost of capital is standard in the literature on which my evidence is based. The second part of this section shows how to adapt the literature's findings to the Board's approach, which is first to specify the cost of equity and then to assess the appropriate capital structure.

9 For those viewing this document in colour, the convention in Figures 1-3 and 5 is that blue represents equity, red represents debt, green represents increases in value, and yellow represents decreases in value.

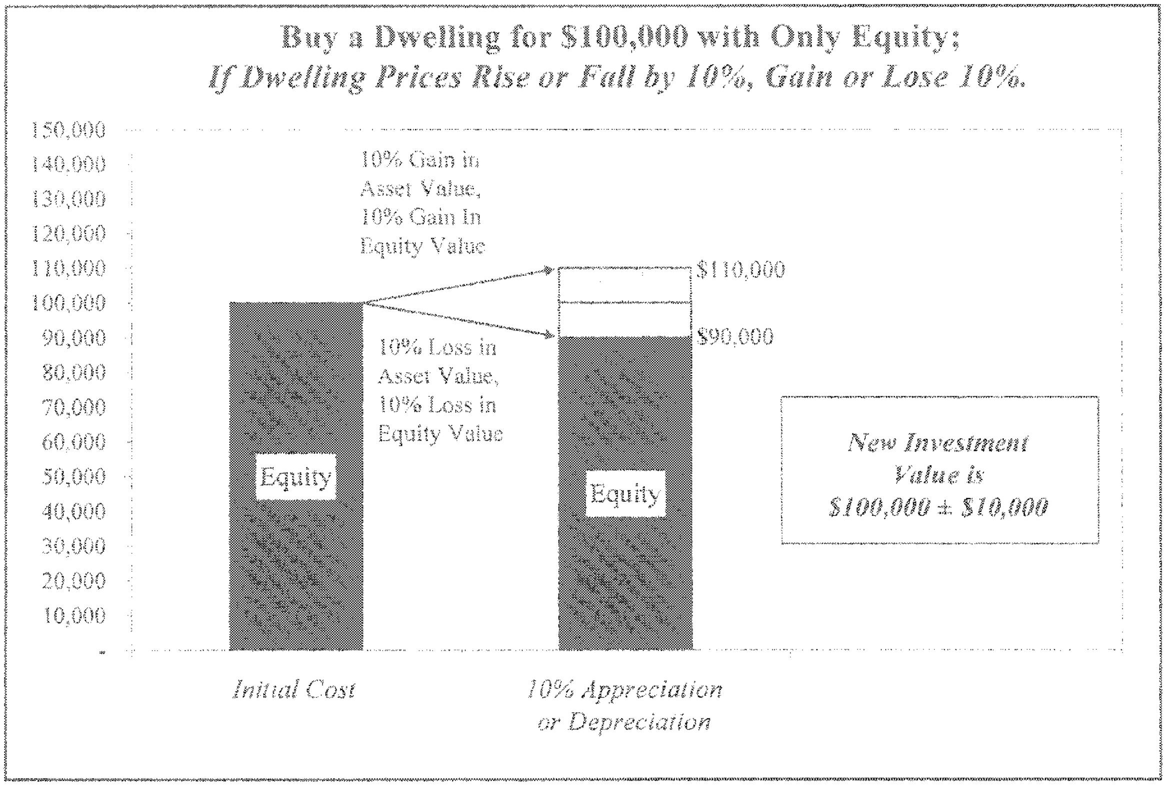


**Figure 1**

Now suppose they don't want to take the full $100,000 out of their savings, or they don't have that much saved, so they take out a mortgage for half the money needed. The mortgage lender does not expect to share in the benefits of rising housing prices, nor to bear the pain of falling ones. They owe the lender $50,000 either way. That means their equity investment bears the entire risk of changing dwelling prices. Figure 2 illustrates this effect.

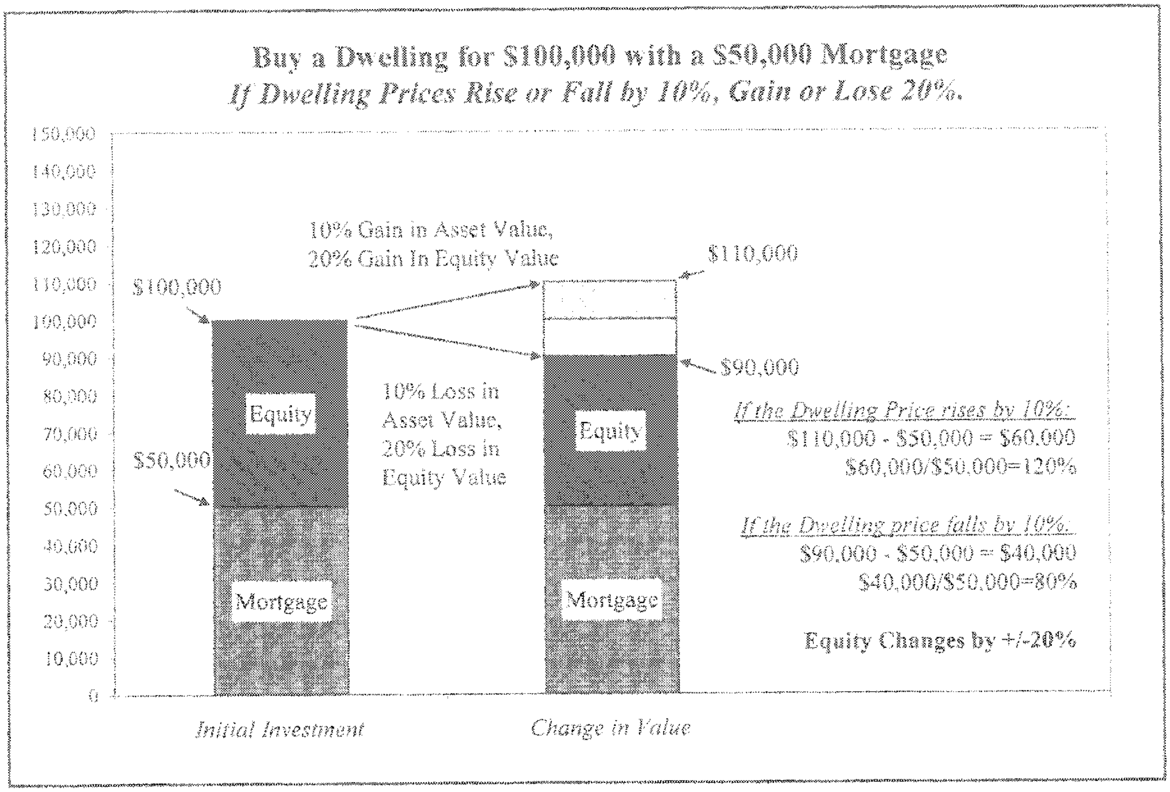


**Figure 2**

Now the variability of their equity return due to the dwelling's price fluctuations doubles. The entire variability of a 10 percent increase in housing prices now falls on the $50,000 in original equity.

**Q12. What happens if the mortgage is a different proportion of the initial dwelling price?**

A12. The equity return gets ever more variable as the mortgage proportion grows. Figure 3 shows the outcome for mortgages that are 0 percent, 20 percent, 50 percent and 80 percent of the initial dwelling purchase price.

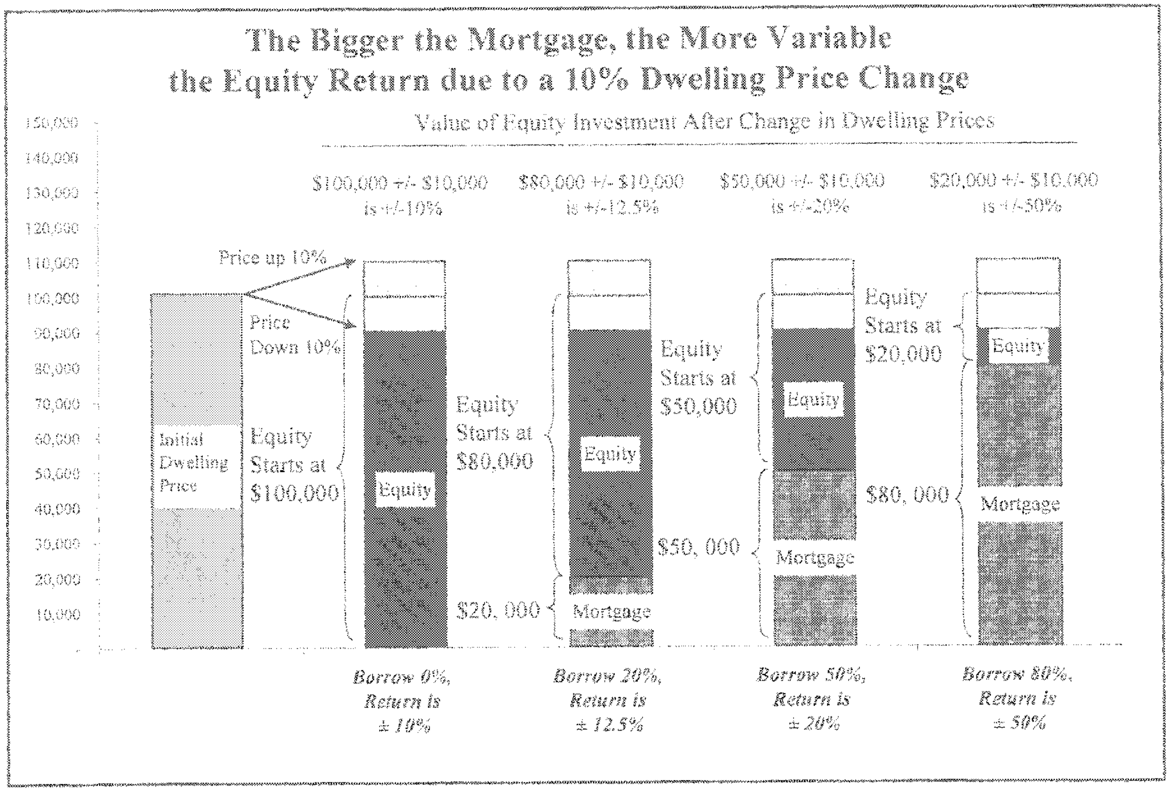


**Figure 3**

Figure 4 depicts the same point in a different way. It shows the growing variability of the equity return as the mortgage proportion increases for a more nearly continuous set of cases. The basic message is the same either way: a higher mortgage (more debt) means ever more risk for equity.

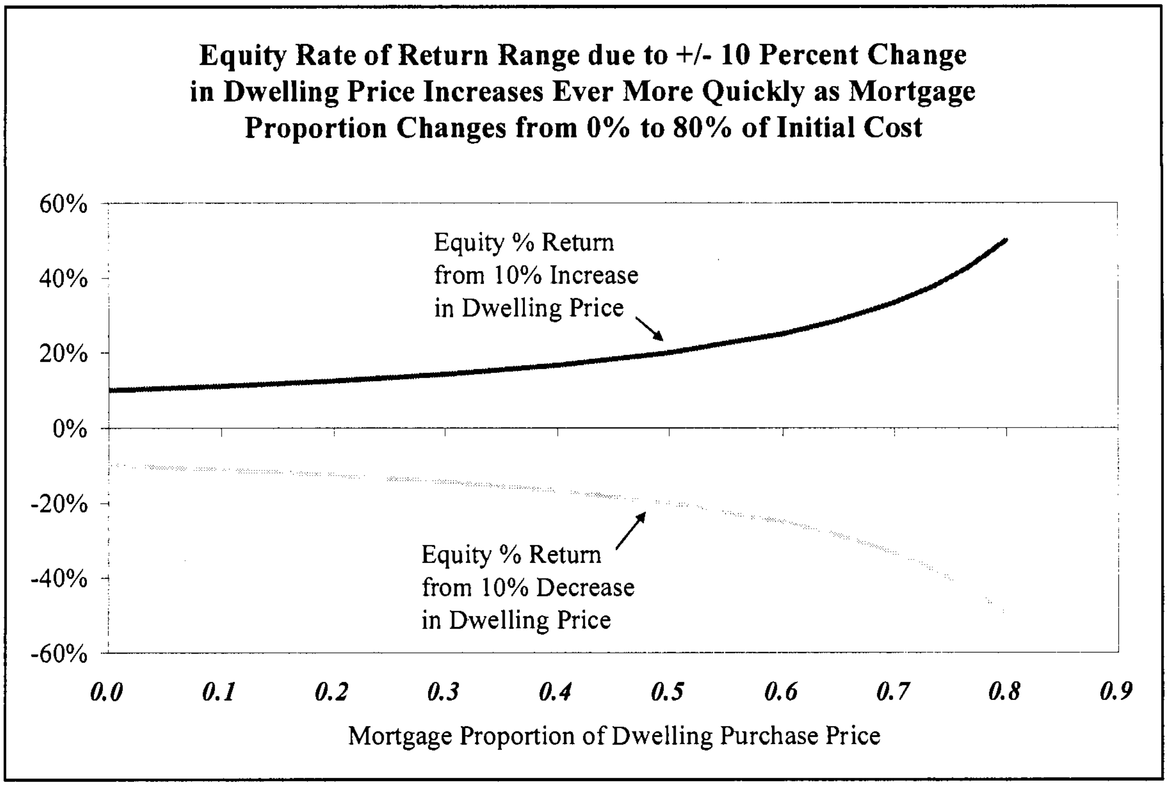


**Figure 4**

**Q13. What does all this mean for the cost of equity?**

A13. Investors do not like risk. For the same expected rate of return on equity, rational investors would choose to be on the left edge of Figure 4, not somewhere to the right. No investor would choose an investment with an expected return of, say, 10 percent plus or minus 50 percent over one with an expected return of 10 percent plus or minus 5 percent. Investors demand a higher rate of return to bear more risk.

The messages of this example are simple:[10]

[10] Appendix B shows that these points hold generally. That is, the fact that the example omits rent (operating income), interest on the mortgage (corporate interest expense) and taxes does not affect these (continued...)

1. ***Debt magnifies equity's risk.***

2. Debt magnifies equity's risk ***at an ever increasing rate.*** Therefore,

3. ***The required rate of return on equity goes up at an ever increasing rate as a company adds more debt.***

This is not only basic finance theory, it is the everyday experience of anyone who buys a home. The bigger the mortgage, the more percentage risk the equity faces from changes in housing prices. (Please recall Figures 3 and 4.)

**Q14. Should you use market-value or book-value capital structures to assess the degree to which financial risk affects the cost of equity?**

A14. The market-value capital structure is the relevant quantity for analyzing the cost of equity evidence, not the book-value capital structure.[11] For example, the variability of the equity in the dwelling illustration depends on the market-value shares of the mortgage and the equity, not the book-value shares. This is true for all companies, even those regulated on

---

[10] (...continued)
conclusions in any way. Nor is the example contrary to modern models of cost of equity causation, which assume risk consists of a stock's sensitivity to one or more economic factors that affect asset values generally. Broad economic forces that lead to fluctuations in asset values lead to even greater fluctuations in equity values if the assets are partly financed by debt, which directly affects the equity beta (or "betas," in multi-factor models).

[11] The need to use market-value capital structures to analyze the effect of debt on the cost of equity has been recognized from the beginning of the financial literature on the topic. For example, the initial reconciliation of the Modigliani-Miller theories of capital structure with the Capital Asset Pricing Model, in Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporation Finance, *The Journal of Finance* 24:13-31 (March 1969), works with market-value capital structures. For a more recent presentation of the concept, see, for example, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, 8th ed., New York: McGraw-Hill/Irwin (2005), at 504-05. Book values may be relevant for some issues, e.g., for covenants on individual bond issues, but as explained in the text, market values are the determinant of the impact of debt on the cost of equity.

a book-value rate base, because the cost of equity depends on the co-variability of the market value of equity with the risk factor(s) that matter to investors.

### B. IMPLICATIONS FOR RATE REGULATION

**Q15. Please sum up the implications of this section.**

A15. The market risk, and therefore the cost, of equity depends directly on the market-value capital structure of the company or asset in question. It therefore is impossible to compare validly the measured costs of equity of different companies without taking capital structure into account. Capital structure and the cost of equity are unbreakably linked, and any effort to treat the two as separate and distinct questions violates both everyday experience (e.g., with home mortgages) and basic financial principles.

**Q16. How should an analyst implement this principle?**

A16. The answer springs from decades of scholarly research. As discussed further in my Appendix B, that research has focused on the effects of capital structure on the value of the firm. However, while the focus is on firm value rather than the cost of capital, the findings have direct implications for the overall cost of capital that should be used both in firms' investment decisions and in rate regulation.

In particular, one of the key conclusions that result from the research is that no narrowly defined optimal capital structure exists within industries, although the typical range of capital structures does vary among industries.[12] Instead, there is a relatively wide

[12] An exception is very high-risk industries that should avoid debt entirely, which makes their optimal capital structure zero percent debt. Such industries have no relevance to the present situation, and so (continued...)

range of capital structures within any industry in which fine-tuning the debt ratio makes little or no difference to the value of the firm.

**Q17. Please summarize how the research reaches this conclusion.**

A17. A full explanation is in Appendix B. Briefly, firms that use no debt forego the tax shield that interest expense provides, and so are less valuable than firms that use some debt. But firms that use too much debt run into a variety of costs and risks, up to and including outright bankruptcy, which means they are less valuable than firms that avoid excessive debt. Therefore, the maximum value of the firm is somewhere in between the extremes. In other words, a plot of the value of the firm against the debt ratio, from zero percent debt to 100 percent debt, produces a hill-shaped curve, higher in the middle than on the ends. The issue is whether the maximum firm value corresponds to a narrow or a broad range of capital structures. That is, is the hill more pointed or more flat on top? The empirical answer is, the hill is quite flat on top. Debt does not have a material effect on the value of the firm within a broad middle range of capital structures. Appendix B provides details.

**Q18. What does this finding imply for the cost of capital?**

A18. Since firm value is independent of capital structure within a broad middle range, the cost of capital used to calculate that value in a standard investment project evaluation must also be independent of capital structure within that range.

[12] (...continued)
are ignored in the remainder of this discussion.

**Q19. Please explain.**

A19. The standard investment valuation approach is to discount the expected all-equity after-tax operating cash flows an investment will generate (i.e., the after-tax cash flows that would be expected if no debt at all were used) at the risk-appropriate after-tax weighted-average cost of capital.[13] The all-equity operating cash flows by definition do not vary with capital structure, so for the resulting value to be independent of capital structure within a broad middle range of capital structures, as the research finds, the after-tax weighted-average cost of capital cannot vary within that range, either.[14]

Accordingly, analysts should treat the market-value weighted average of the cost of equity and the after-tax current cost of debt, or the "ATWACC" for short,[15] as constant. Sample evidence should be analyzed to estimate the sample's average ATWACC, which can be compared "apples to apples" across different firms or industries. The ATWACC is the most fundamental measure of the required return associated with a particular business, since it reflects the basic risk of the *assets* devoted to the business.

In contrast, the costs of capital of debt and equity are not fundamental, but rather flow from the cost of capital of the assets. They differ from the cost of capital of the assets and from each other because debt has a priority claim on the firm's cash flows, which loads

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[13] See, for example, Brealey, Myers and Allen, *op. cit.*, Chapter 19.

[14] *Ibid.*, p. 520.

[15] This quantity typically is called the "weighted-average cost of capital" or "WACC" in finance textbooks. The textbook WACC equals the *market*-value weighted average of the cost of equity and the *after-tax*, *current* cost of debt. However, rate regulation in North America has a legacy of working with another weighted-average cost of capital, the *book*-value weighted average of the cost of equity and the *before-tax*, *embedded* cost of debt. Accordingly, in regulatory settings it's useful to refer to the textbook WACC as the "ATWACC," or "after-tax weighted-average cost of capital." I follow that practice here.

(most of) the assets' risk onto the equity. The risk that equity bears (and hence its cost of capital) thus changes materially as capital structure changes. But the weighted sum of the costs of debt and equity must always reflect the underlying, fundamental risk of the assets.

Rate regulation needs to offer investors a fair opportunity to earn the rate of return determined in competitive capital markets. The economically appropriate *regulatory* equity ratio for a regulated firm is the quantity that, when applied to the formula rate of return on equity, produces the same, market-determined ATWACC. That value is the market-value equity ratio that a comparable-business-risk sample would have had, estimation problems aside, if the sample's cost of equity were equal to the formula rate of return on equity in question. Any other result would imply that the sample had a different level of business risk.

**Q20. Can you illustrate how this procedure would work?**

A20. Yes, but a full explanation requires several steps. Look first at Figure 5, which takes the literature's perspective, i.e., that the analysis concerns how the addition of debt affects the cost of capital. Here the after-tax weighted-average cost of capital is shown as mildly U-shaped, which is just the inverse of the mildly "hill-shaped" curve for the value of the firm discussed immediately above.[16] Consistent with the research, the ATWACC curve is drawn to be essentially flat in a broad middle range, here between market-value capital structures of about 35 and 70 percent debt (i.e., 65 to 30 percent equity), or perhaps

[16] Since the all-equity operating cash flows are independent of capital structure, the only way for the value of the firm to be lower at extreme capital structures (and thereby to produce a hill-shaped curve for the value of the firm as a function of capital structure) is if the discount rate used to calculate firm value (i.e., the ATWACC), is higher at extreme capital structures -- that is, if it is shaped like a U.

between 40 and 65 percent debt (i.e., 60 to 35 percent equity). If the overall cost of capital is essentially constant as the proportion of risk-bearing equity shrinks, the risk and cost of equity must rise at an ever-increasing rate. The figure shows this effect in the cost of equity curve.

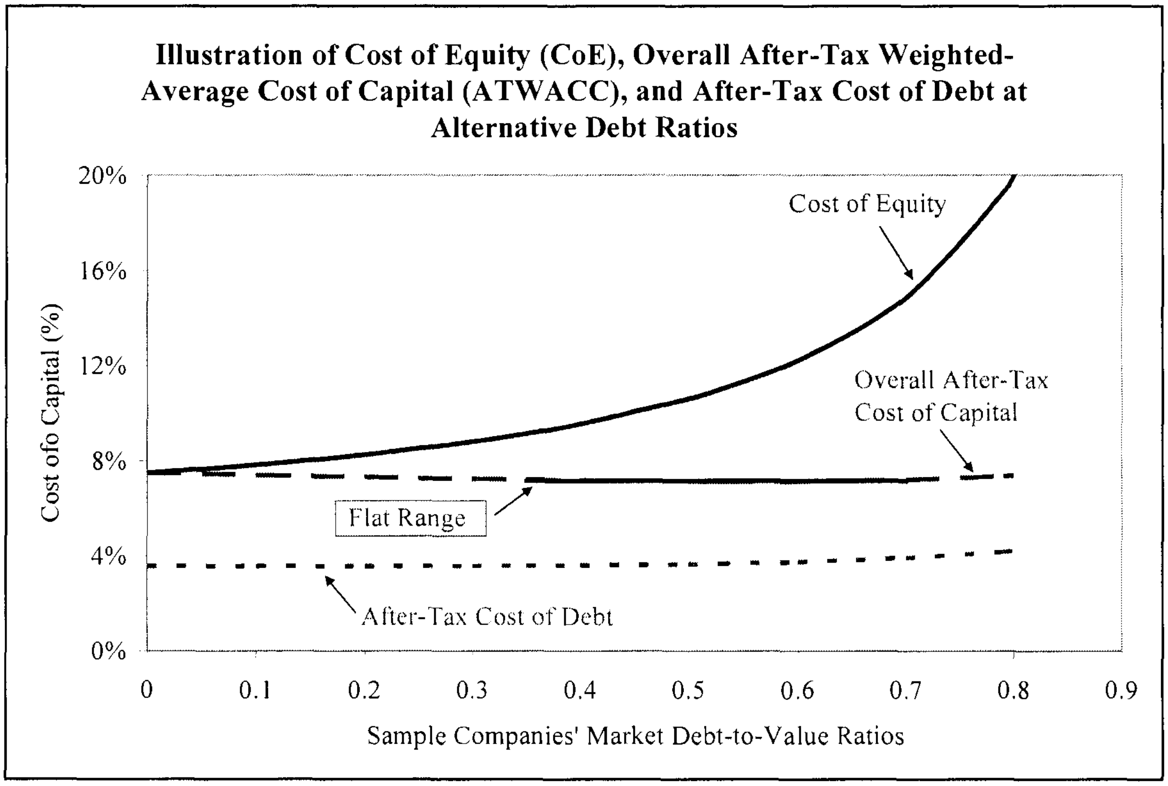


**Figure 5**

Suppose an analyst examines a sample of firms in this industry and estimates a value for the ATWACC at the sample's actual average market-value debt ratio. Then (estimation errors aside) s/he would have found a different cost of equity had the sample had a higher debt ratio, because the sample's equityholders would have been bearing more financial risk at the higher debt ratio. (Recall Figure 3 or 4.) However, the cost of equity that went with the alternative debt ratio could readily be calculated from the information in Figure 5. Figure 6 illustrates the process: simply specify the alternative debt ratio on the horizontal axis, and calculate the associated cost of equity on the vertical axis. (Of course, in practice we do not know the precise shape of the ATWACC curve, but Figure 5 illustrates the finding that the alternative cost of equity can be found very accurately by treating the sample ATWACC as flat in a middle range of capital structures.)

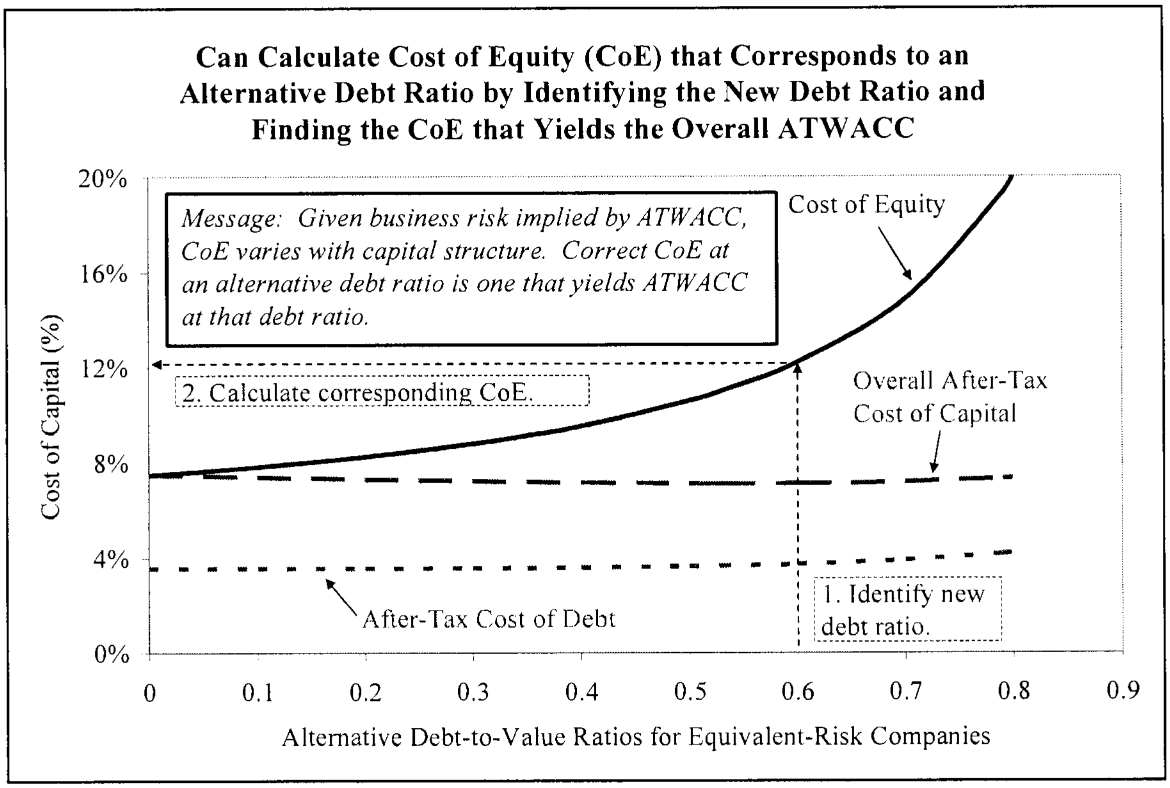


**Figure 6**

Under the Board's procedures, however, the cost of equity is set by the Board's formula, and the deemed equity ratio is specified to correspond to the utility's business risk. This approach is easily accommodated, by turning Figure 6 on its side. Figure 7 does so. To recognize the Board's focus on the equity ratio instead of the debt ratio, Figure 7 uses the equity ratio as the vertical axis and the rate of return as the horizontal axis. This amounts to rotating Figure 6 by 90 degrees clockwise. Now the formula cost of equity is specified on the horizontal axis, and the deemed equity ratio that corresponds to the sample's overall business risk calculated on the vertical axis.

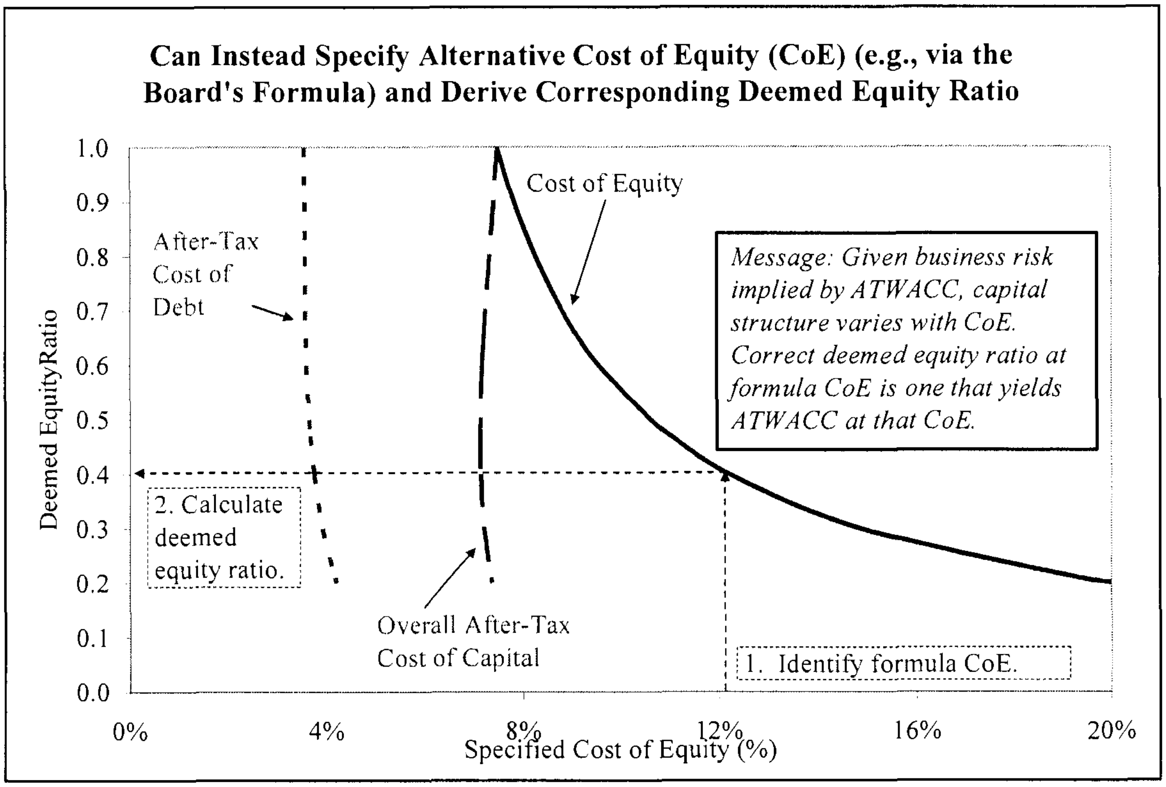


**Figure 7**

This process leads to a ready three-step procedure to use in rate hearings:

1. Calculate the after-tax weighted-average cost of capital for a sample of companies not in financial difficulty,[17] using each company's market-value capital structure and its current after-tax market cost of debt;

[17] Companies in financial distress will be beyond the middle range of capital structures. To avoid such companies, Dr. Vilbert excludes from his samples any companies without investment-grade debt. He also would reject any sample company with 100 percent equity, since that capital structure also would lie outside the middle range in Figures 6-8, but in the other direction.

2. Take the average of these values as the industry's after-tax weighted-average cost of capital, and

3. Calculate the regulated company's deemed equity ratio as the value that produces the same after-tax weighted-average cost of capital at the current value for the Board's formula cost of equity, again using the company's current after-tax market cost of debt.

The result will be the deemed equity ratio that yields the ATWACC that the market requires. That deemed equity ratio is also the market-value equity ratio that the analyst would have observed, estimation problems aside, if the sample's market cost of equity had been equal to the Board's formula value. For these reasons, that value is the appropriate allowed deemed equity ratio at the formula cost of equity.

Dr. Vilbert and I implement this procedure to assess sample risk return evidence and the implications for Union's appropriate deemed equity ratio. This approach permits explicit, quantitative analysis of the deemed equity ratio that is economically consistent with the sample evidence, based on principles in wide use in Commonwealth countries that have adopted rate regulation more recently.[18] I believe such quantitative analysis can and should be a valuable addition to the techniques used by the Board in the past.

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[18] In this regard, I would note that North America came early to the realization that private ownership of industries affected with a public interest, overseen by public regulatory bodies, has net economic advantages over public ownership. In recent years other regions have been switching to the North American model. But the delay gives those regions the advantage of access to decades of financial research not available when North American rate regulation began. As a result, countries such as Australia, New Zealand and the United Kingdom have all incorporated procedures to address differences in financial risk that are equivalent to those I recommend here. Similar procedures have recently been adopted in Missouri, although using the usual U.S. approach of taking capital structure as given and calculating the cost of equity to allow. See the decision in Missouri Public Service Commission, Case No. ER-2004-0570, Tariff File No. YE-2004-1324, for The Empire District Electric Company, issued March 10, 2005.

## III. CONCLUSIONS FOR UNION'S DEEMED EQUITY RATIO

**Q21. On what are your conclusions based?**

A21. As noted at the outset of my evidence, I base my conclusions on Dr. Carpenter's evidence on risk and Dr. Vilbert's evidence on the risk-return information from benchmark sample groups. I also rely on my own experience in assessing risk and return for dozens of lines of business, regulated and unregulated alike, in North America, Australia and Europe. This section reports my analysis of this evidence in order to determine Union's deemed equity ratio.

### A. THE CARPENTER AND VILBERT RISK-RETURN EVIDENCE

**Q22. What "bottom line" do you take from Dr. Carpenter's and Dr. Vilbert's evidence?**

A22. Their evidence is extensive and speaks for itself, but I would note particularly that Dr. Carpenter concludes that Union's business risk has recently increased and that Union is more risky than Dr. Vilbert's LDC sample. In the same spirit of brevity, I note that Dr. Vilbert concludes that for his Canadian sample, the deemed equity ratio range at a 9.63 percent rate of return on equity is 40 percent to 48 percent, with a midpoint of 44 percent.[19] For his sample based on U.S. gas distribution company relative risks and Canadian capital

[19] With the current values for the Board's formula rate of return on equity, the cost of debt, and the tax rate, a four percentage point swing in the deemed equity ratio corresponds to approximately a ¼ percentage point swing in the corresponding calculation of the company's ATWACC, and to something over a ½ percentage point swing in the corresponding cost of equity, depending on the starting point. I do not believe it is possible to estimate the cost of capital more accurately than to the nearest ¼ percentage point with the current state of the art. Dr. Vilbert and I therefore state the deemed equity ratio for a particular sample in increments of at least four percentage points when interpreting the sample risk-return evidence on the deemed equity ratio in this proceeding.

market benchmarks, he also finds the range to be 42 percent to 50 percent, with a midpoint of 46 percent. The corresponding values at an 8.89 percent rate of return on equity are, for the Canadian sample, 46 to 54 percent, midpoint 50 percent, and for the LDC sample, 48 to 56 percent, midpoint 52 percent.

## B. CONCLUSIONS ON UNION'S DEEMED EQUITY RATIO

**Q23. How is this discussion organized?**

A23. It first addresses the basis of my conclusions on Union's deemed equity ratio. It then provides additional, quantitative information on the relationships between Dr. Vilbert's sample findings and my recommendations for Union.

### 1. Deemed Equity Ratio Conclusions

**Q24. What is the basis of your conclusions for Union's required deemed equity ratio, given the above evidence?**

A24. The chief difficulty in determining Union's deemed equity ratio at the Board's formula rate of return on equity at this time is in assessing Union's risk relative to those of the sample groups. Dr. Carpenter's conclusion that Union's risk has increased and that it is greater than that of the LDC sample is in part due to increased competitiveness in Union's storage and transmission operations. In this regard, I would note that competition normally increases the volatility of a company's rates of return, and hence its risk. Moreover, my own research confirms that regulated companies often have a good deal of difficulty adapting to competition successfully, in part due to their own cultures and in part due to regulatory constraints.[20] Also, the combination of regulation and competition can be very harmful, since regulation can constrain rates at times competition would permit higher charges and conversely, leaving the regulated company facing "the lower of cost or market" in the rates it can charge.[21] Thus, I, too, believe that Dr. Vilbert's LDC sample results will tend to understate the deemed equity ratio that Union should receive.

Dr. Vilbert's Canadian sample is less homogeneous, and therefore harder to benchmark against Union. Additionally, problems with conventionally calculated betas in recent years have forced him to rely on betas estimated from a series of 52-week beta values. All else equal, one-year betas are less reliable, but here all else is not equal. Moreover, Dr. Vilbert adopts procedures, described in his evidence, to eliminate dependence on a single 52-week beta estimate for his sample. Given the circumstances, I agree with his decision to use the betas he does; in fact, I believe these betas are materially more reliable than those that have been available for Canadian rate-regulated energy companies in recent years.

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[20] For example, competition requires quick responses and thrives on service differentiation. Regulation requires a formal oversight process and administratively manageable (i.e., fairly homogeneous) service offerings. Regulated companies (and their regulators) therefore need to learn to respond to new conditions more quickly when facing competition as well as regulation, but the very nature of regulation may retard the development of the skills or tools the company needs. The kinds of problems that can arise are discussed, for example, in A. Lawrence Kolbe and Richard W. Hodges, "EPRI PRISM Interim Report: Parcel/Message Delivery Services," report prepared for the Electric Power Research Institute, RP-2801-2 (June 1989), reprinted in S. Oren and S. Smith, eds., *Service Opportunities for Electric Utilities: Creating Differentiated Products*. Boston: Kluwer Academic Publishers (1993). The inability to respond quickly to a more nimble competitor (United Parcel Service) cost the U.S. Post Office most of the package delivery business and drove the Railway Express Agency entirely out of business.

[21] See Stewart C. Myers, A. Lawrence Kolbe and William B. Tye, "Inflation and Rate of Return Regulation," *Research in Transportation Economics*, Volume II. Greenwich, CT: JAI Press, Inc. (1985), or Kolbe, Tye and Myers, *op. cit.*, Chapter 4.

**Q25. What specific values do you recommend for Union's deemed equity ratio at the Board's formula 9.63 percent rate of return on equity?**

A25. Dr. Carpenter's evidence and my own understanding of the effects of competition on rate-regulated operations lead to the conclusion that Union is somewhat riskier than Dr. Vilbert's LDC sample, although it is difficult to say by exactly how much. My analysis must interpret this conclusion in terms of Dr. Vilbert's quantitative evidence on deemed equity ratios for the benchmark samples. To do so, I assess (1) the relative risks of Union and Dr. Vilbert's actual samples, and (2) the characteristics of those samples, in order to determine what deemed equity ratio results would be expected for a large sample of companies identical to Union.

As noted, Dr. Vilbert's LDC sample is larger, more homogeneous, and more stable, and so deserves more weight in this analysis. However, Dr. Vilbert's procedures to estimate materially more reliable Canadian sample betas than those available in recent years mean the Canadian sample deserves more weight than it otherwise would, given its problems (e.g., its heterogeneity). Considering all of the evidence, I believe, first, that Union's deemed equity ratio clearly lies, at a minimum, in the range from the bottom of the Canadian sample to the top of the LDC sample, or 40 to 50 percent at the 9.63 percent return on equity. It may well be higher, given Union's transportation and storage risks. Given the sample evidence and its relative merits, and Union's relative risk level, I further conclude that the best estimate of the appropriate deemed equity ratio for Union lies in the upper half of that range. The corresponding conclusion at the 8.89 percent rate of return on equity puts Union's appropriate deemed equity ratio in the upper half of a range from 46 to 56 percent equity.

The Company's requested value of 40 percent lies at the bottom of my range for a 9.63 percent return on equity, which is below the best estimate of the level I believe the evidence supports. It is even further below the appropriate range at a 8.89 percent return on equity. I demonstrate this point with graphs in the final part of my evidence.

### 2. Equity Ratio-Rate of Return on Equity Tradeoffs and Comparisons

**Q26. Earlier you indicated you would provide an explicit analysis of the tradeoff between the deemed equity ratio and Board's formula value for the rate of return on equity, to quantify how the recommended deemed equity values compared to the sample evidence. Please provide this analysis for your deemed equity ratio recommendations.**

The numbers cited above already rely on the capital structure-cost of equity procedures I recommend. However, to respond to this request, I provide a graph of how the deemed equity ratio curves that correspond to Dr. Vilbert's conclusions relate to my own deemed equity ratio findings. As noted earlier, Dr. Vilbert finds the mid-point deemed equity ratio to be 44 percent at the current formula value for his Canadian sample and 46 percent for his LDC sample, at the 9.63 percent return on equity. As just noted, my own analysis concludes that Union's deemed equity ratio should be in the upper half of a range from 40 percent to 50 percent at the 9.63 percent formula rate of return on equity. Figure 8 plots the associated deemed equity ratio equity curves and indicates various relevant points on them.

Note that the curves have the same basic shape as the cost of equity-equity ratio curve in Figure 7, but the scale on the horizontal axis is spread out to permit a focus on the values relevant to Dr. Vilbert's results. The "sample data" points plot the average market-value capital structures of the samples at the cost of equity values derived from the most reliable of Dr. Vilbert's estimation methods.[22] The curves through these data points plot the capital structure-cost of equity combinations that are consistent with the level of business risk implied by the sample evidence, at alternative levels of financial risk. Figure 8 also plots Union's requested 40 percent equity ratio at both the 8.89 and 9.63 percent rates of return on equity.

Please note that the latter return on equity falls squarely on the line tracing out the bottom of my range, while the former lies well below any level supported by the risk-return data. However, note also that the appropriate deemed equity ratio for both samples at both values for the Board's formula return on equity (which are found by tracing down one of the curves to the particular formula return on equity value) lie below the actual equity ratios of the sample companies. This is because both of the Board's formula values offer more compensation for financial risk than the samples' actual cost of equity values at their actual, higher equity ratios. This fact illustrates the need to adjust for differences in financial risk when interpreting sample evidence on deemed equity ratios: the samples' actual equity ratios exceed the level appropriate for Union according to any particular curve.

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[22] This is his middle model, the Empirical Capital Asset Pricing Model -- "ECAPM" -- with a value of one percent for the constant term. See Dr. Vilbert's evidence. The LDC line uses the equity-to-value ratio that corresponds to the average debt/equity ratio of Dr. Vilbert's LDC subsample, since the cost of equity is linearly related to the debt/equity ratio, not the debt-to-value ratio. See Appendix B. (Dr. Vilbert's procedures for his Canadian sample follow this procedure, also.)

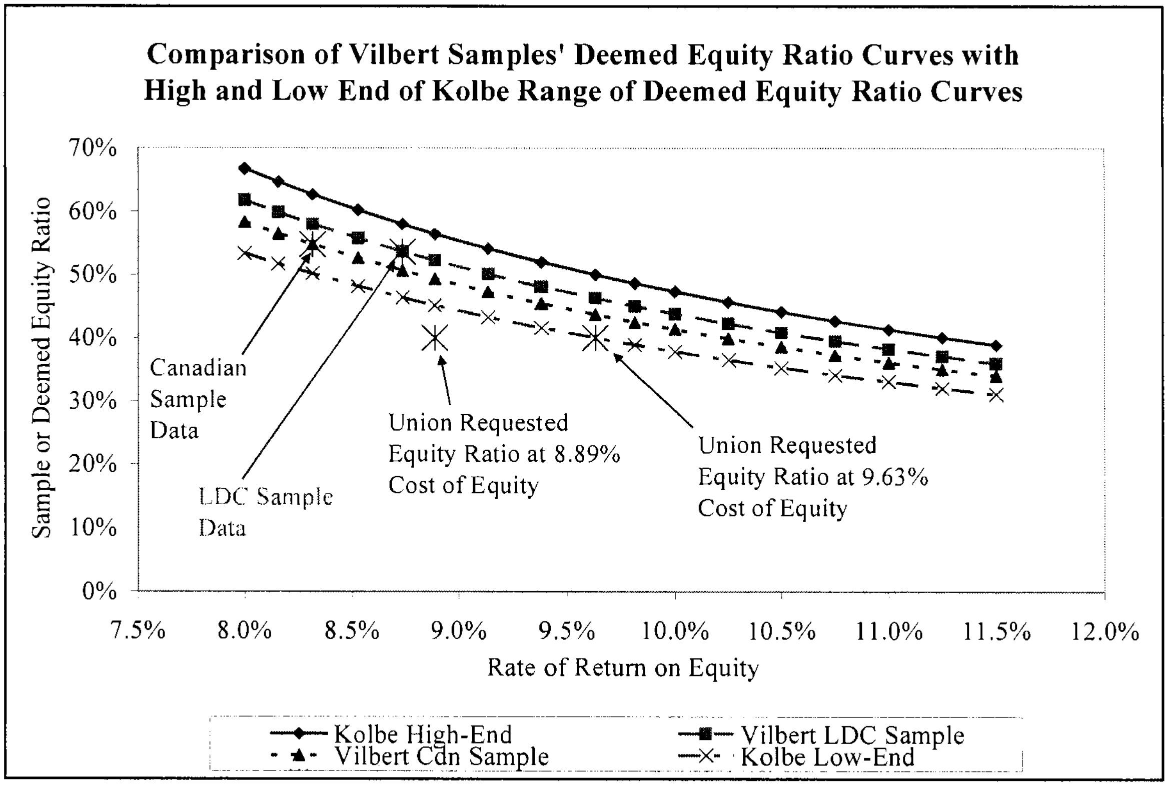


**Figure 8**

These results are particularly significant in view of my conclusion that Union's deemed equity ratio should lie in the upper half of the range, not at or below the bottom. The fact that Union's requested equity ratio is at or below the bottom of my range shows why Union's request is very conservative relative to the results of the risk-return evidence. In fact, there is another way to make this point as well.

**Q27. What is that?**

A26. Please look at Figure 9. This figure adds a new line,[23] which represents Dr. Vilbert's Canadian sample deemed equity ratio curve based on the Capital Asset Pricing Model ("CAPM"), rather than the ECAPM. The market-value capital structure is the same, but the cost of equity is lower, so the Canadian sample curve based on the CAPM shifts to the left and always lies below the base ECAPM curve. In fact, it shifts so far to the left that a new point needs to be added on the left edge of the graph. This is the lowest deemed equity ratio curve that can be derived from Dr. Vilbert's risk positioning analyses.

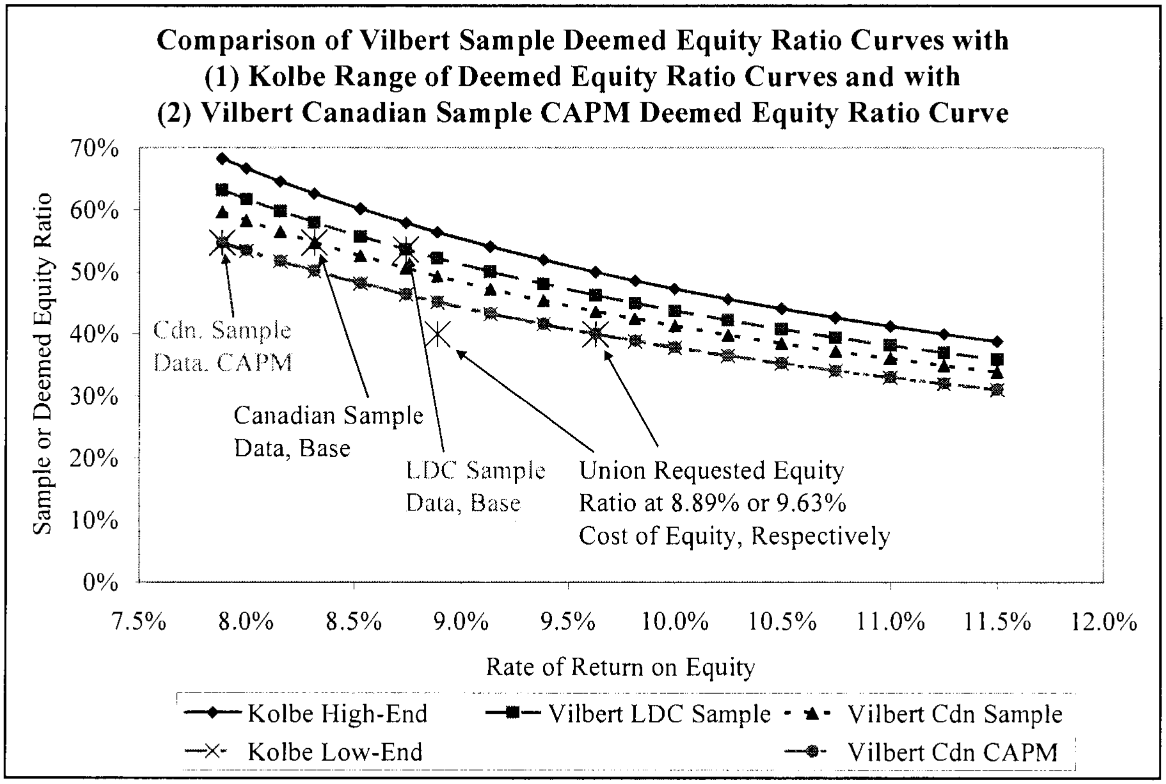


**Figure 9**

The key point is that even the Canadian sample, CAPM-based deemed equity ratio equation produces a deemed equity ratio equal to that Union has requested *if* the final

[23] In a lighter shade of blue, in colour copies.

return on equity value used for Union proves to be 9.63 percent. If the value proves to be closer to the 8.89 percent value, Union's request lies below a deemed equity ratio supported by any of the risk-return evidence. This reinforces my conclusion that Union's 40 percent deemed equity ratio request is at the very bottom of the possible levels warranted by the risk-return evidence my colleagues and I present in this proceeding.

**Q28. Does this complete the main body of your written evidence?**

A27. Yes, it does.

WRITTEN EVIDENCE OF
A. LAWRENCE KOLBE

## APPENDIX A: QUALIFICATIONS OF A. LAWRENCE KOLBE

A. Lawrence Kolbe is a Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge (Massachusetts), Washington, London, San Francisco, and Brussels. Before co-founding The Brattle Group, he was a Director of Putnam, Hayes & Bartlett, and before that, he was a Vice President of Charles River Associates ("CRA"). Earlier, he was an Air Force officer assigned to the Office of the Secretary of Defense with the job title "Health Economist," and before that, he was assigned to Headquarters, USAF with the job title "Systems Analyst."

His work has included extensive research in financial economics, especially as it applies to rate regulation, project or asset valuation, and the decisions of private firms. Clients for this work include the California Public Utilities Commission, the Consumer Advocate in a Newfoundland proceeding, the Edison Electric Institute, the Electric Power Research Institute, the Interstate Natural Gas Association of America, the Newfoundland Federation of Municipalities, the Nova Scotia Board of Commissioners of Public Utilities, the Town of Labrador City, the U.S. Department of Energy, the U.S. Department of Justice, the U.S. Department of State, and a number of private firms.

He is the coauthor of three books and he has published a number of articles. He is coauthor of a report filed with the British Office of Fair Trading, in London, and he has been an expert witness in: proceedings before the U.S.-U.K. Arbitration Concerning Heathrow Airport Landing Charges (under the auspices of the International Bureau of the Permanent Court of Arbitration) in The Hague, the Iran-United States Claims Tribunal in The Hague, the U.S. Court of Federal Claims, U.S. District Courts in Arizona, Colorado, Florida, New Jersey, Oklahoma, Pennsylvania, Texas and Virginia, the Supreme Court of the State of New Mexico, Colorado District Court, a commercial arbitration tribunal in Australia, a commercial arbitration tribunal held in London concerning a dispute in Australia, the Minerals Management Service of the U.S. Department of the Interior, the Master Settlement Agreement Tobacco Arbitration Panels for the State of Louisiana and the Commonwealth of Massachusetts (which determined fee awards to private counsel assisting the state), and a commercial arbitration in Arizona; federal regulatory proceedings before the Canadian Radio-television and Telecommunications Commission, the [Canadian] National Energy Board, the [U.S.] Postal Rate Commission, the [U.S.] Surface Transportation Board, the U.S. Federal Communications Commission, the U.S. Federal Energy Regulatory Commission and the U.S. Federal Maritime Commission; and state or provincial regulatory proceedings in Alaska, Alberta, Arizona, Arkansas, California, Connecticut, Illinois, Maine, Massachusetts, Michigan, Montana, Newfoundland, New Mexico, New York, Nova Scotia, Ohio, Virginia and West Virginia.

He holds a B.S. in International Affairs (Economics) from the U.S. Air Force Academy and a Ph.D. in Economics from the Massachusetts Institute of Technology. Additional information on his qualifications follows.

### HONOURS AND AWARDS

Sears Foundation National Merit Scholarship, 1963 (declined).
Fairchild Award, U.S. Air Force Academy, 1968 (for standing first in his class, academically).
National Science Foundation Graduate Fellowship in economics, MIT, 1968-1971.

Joint Service Commendation Medal, 1975.

## PROFESSIONAL AFFILIATIONS

American Economic Association
American Finance Association
The Econometric Society
Served as Referee for *The Rand Journal of Economics*, *Land Economics*, *The Journal of Industrial Economics*

## AVAILABLE PAPERS AND PUBLICATIONS

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly* (with Michael J. Vilbert and Bente Villadsen), August 2005.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with Michael J. Vilbert and Bente Villadsen, and with "The Brattle Group" listed as author), published by the Edison Electric Institute (dated January 2005, issued April 2005)

*Capital Investment and Valuation*, (with Richard A. Brealey and Stewart C. Myers, with "The Brattle Group" listed as third author), New York: McGraw-Hill/Irwin (2003).

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"A Note on the Pre-tax Weighted Average Cost of Capital in a Regulatory Context with Australian Dividend Tax Credits and Alternative Debt Refinancing Policies" (with M. Alexis Maniatis), Working Paper in Progress.

"The Impact of Stranded-Cost Risk on Required Rates of Return for Electric Utilities: Theory and An Example" (with Lynda S. Borucki). *Journal of Regulatory Economics* Vol. 13 (1998), 255-275.

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"How to Value a Lost Opportunity: Defining and Measuring Damages from Market Foreclosure," (with William B. Tye and Stephen H. Kalos), *Research in Law and Economics* 17, 83-125 (1995).

"Faulty Analysis Underlies Claims of Excess Card Profits", (with Carlos Lapuerta). *American Banker*, October 10, 1995.

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"Purchased Power: Hidden Costs or Benefits?" (with Sarah Johnson, Johannes P. Pfeifenberger and David W. Weinstein). *The Electricity Journal* 7, 74-83 (September 1994).

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"Rate of Return Recommendations in Cable Television Cost-of-Service Regulation" (with Lynda S. Borucki). Brattle report filed in Federal Communications Commission Docket No. 93-215, CS Docket No. 94-28, July 1994.

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"Banking on NUG Reliability" (with Sarah Johnson and Johannes P. Pfeifenberger). *Public Utilities Fortnightly*, May 15, 1994.

"Section 712 Issues: Risk Identification, Allocation and Compensation." Paper presented to National Association of Regulatory Utility Commissioners (July 1993) and published in *Presentations and Papers from the National Seminars on Public Utility Commission Implementation of the Energy Policy Act of 1992.* Columbus, OH: National Regulatory Research Institute, December 1993.

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"Rate of Return Issues in Cable Television Cost-of-Service Regulation" (with Lynda S. Borucki). Brattle report filed in Federal Communications Commission Docket No. 93-215, August 1993.

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"Who Pays for Prudence Risk?" (with William B. Tye), *Public Utilities Fortnightly* (August 1, 1992)."

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"EPA's 'BEN' Model: Challenging Excessive Penalty Calculations" (with Kenneth T. Wise, Paul R. Ammann and Scott M. DuBoff), *Toxics Law Reporter* 6, 1492-1496 (May 6, 1992).

"Optimal Time Structures for Rates in Regulated Industries" (with William B. Tye). *Transportation Practitioners Journal* 59, 176-199 (Winter 1992).

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"The *Duquesne* Opinion: How Much '*Hope*' Is There for Investors in Regulated Firms?" (with William B. Tye). *Yale Journal on Regulation*, Winter 1991, 113-157.

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## APPENDIX B: EFFECTS OF DEBT ON THE COST OF EQUITY

**Q1. What is the purpose of this appendix?**

A1. The body of my evidence illustrates why the use of additional debt increases equity's risk at an ever-increasing rate. This appendix provides additional detail on this issue. It first expands the mortgage-based example used in the body of my testimony. Then it depicts the implications of a large body of financial research. Lastly, it provides a more formal summary of that research.

## I. EXPANDED EXAMPLE

**Q2. The mortgage example in the main body of your evidence did not address rent, interest expense or taxes. Please do so now.**

A2. I start with rent and interest expense, and leave taxes until the next part of the appendix. Rent could affect a dwelling buyer in two ways. First, the buyer could buy the dwelling as an investment or as a future retirement home and rent it out. Second, the dwelling buyer could live there and avoid having to pay rent on an apartment instead. The former seems to be the better analogy for present purposes.

Assume rent on the $100,000 dwelling would net the owner $500 per month on average after all (non-interest) expenses, or $6,000 annually. Suppose also that expected appreciation in housing prices were 4 percent, so its expected value would be $104,000 after the first year. Then the expected rate of return from owning the dwelling if there is no mortgage would be:

$$\text{Expected rate of return @ 0\% Mortgage} = \frac{\text{Expected Net Rent + Expected Value Appreciation}}{\text{Initial } \textit{Dwelling} \text{ Value}}$$

$$= \frac{\$6{,}000 + (\$104{,}000 - \$100{,}000)}{\$100{,}000}$$

$$= \frac{\$6{,}000 + \$4{,}000}{\$100{,}000} = \frac{\$10{,}000}{\$100{,}000}$$

$$= 10\%$$

Suppose also that the mortgage interest rate were 6 percent. Then at a mortgage equal to 50 percent of the purchase price, or \$50,000, interest expense would be (\$50,000 x 0.06), or \$3,000. The expected equity rate of return would be

$$\text{Expected rate of return @ 50\% Mortgage} = \frac{\text{Expected (Net Rent + Value Appreciation) - Interest}}{\text{Initial } \textit{Equity} \text{ Value}}$$

$$= \frac{\$6{,}000 + (\$104{,}000 - \$100{,}000) - \$3000}{\$50{,}000}$$

$$= \frac{\$6{,}000 + \$4{,}000 - \$3{,}000}{\$50{,}000} = \frac{\$7{,}000}{\$50{,}000}$$

$$= 14\%$$

The expected return on equity is higher. However, as illustrated in the figures in the main body of my evidence, so is the risk equity bears.

**Q3. Can you provide a more general illustration?**

A3. Yes. Figure B-1 uses these assumptions at different mortgage levels to plot both (1) the expected rate of return on the equity in the dwelling, and (2) the realized rate of return on that equity in a year if the dwelling value increases by 10 percent more than the expected 4 percent rate (i.e., if the dwelling value increases by 14 percent) or by 10 percent less than expected (i.e., if it decreases by 6 percent).[24]

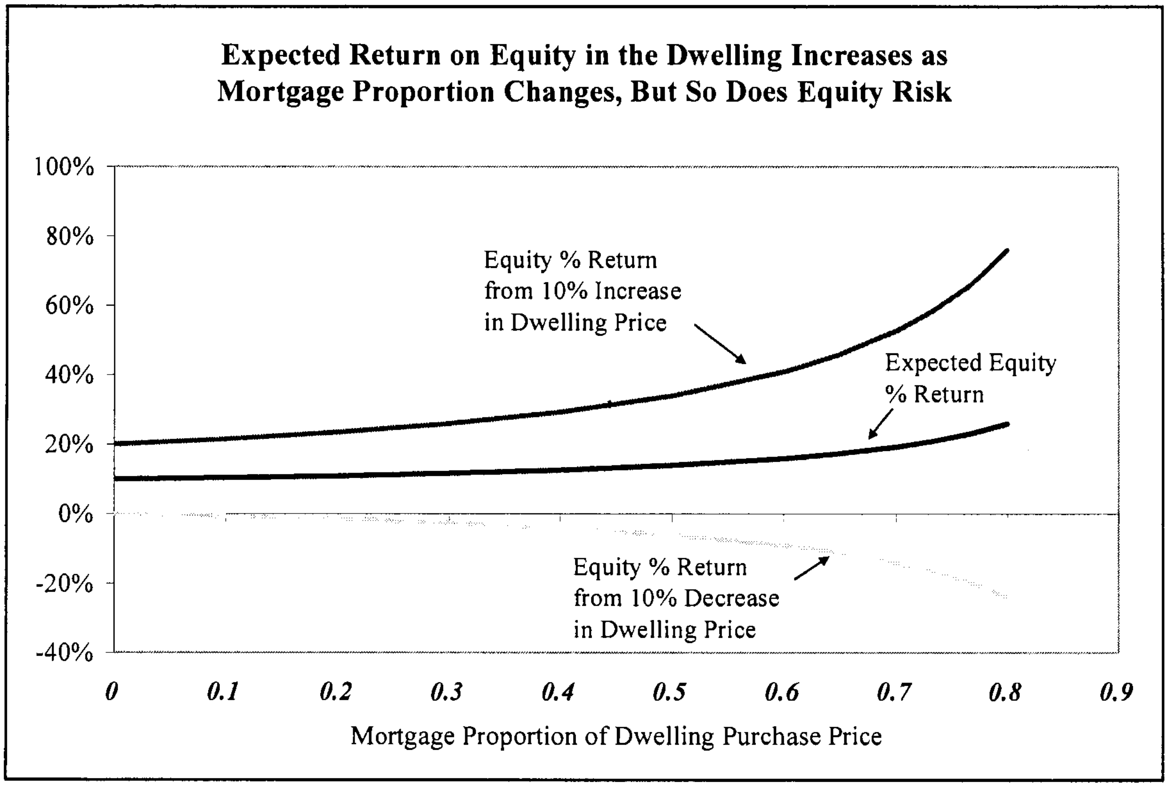


**Figure B-1**

The expected rate of return on equity increases at an increasing rate as the buyer finances more and more of the dwelling with a mortgage. But since (absent financial distress or bankruptcy) equity bears all of the risk of fluctuations in dwelling values, the amount of risk the buyer bears grows at an ever increasing rate at the mortgage percentage

[24] For simplicity, the figure assumes the mortgage interest rate is independent of the mortgage proportion. This might not always be true, and in general would not be true for a corporation that issued debt. However, the same basic picture would emerge if the interest rate varied in a realistic way as the mortgage proportion increased.

increases, too. (The upper and lower lines in Figure B-1 effectively just add the lines from Figure 4 in the body of my evidence to the Figure B-1 expected rate of return on equity.) This means the required rate of return on equity must increase, else the buyer would be bearing risk without reward.

**Q4. Can you provide an example of a deal that would involve bearing financial risk with no reward?**

A4. Suppose someone were to object that they don't think of the equity in their home as requiring a higher expected rate of return just because they use a mortgage, and that they personally would not demand a higher rate of return for this risk. Suppose also that the numbers in the dwelling example above were in front of this person and a potential co-investor in a dwelling. The co-investor would be happy to propose a deal something like the following.

"Why don't we buy the dwelling 50-50. It costs $100,000. We'll finance it 50 percent with a mortgage, so we each put in $25,000 in equity and are individually responsible for $25,000 of the mortgage. We'll rent the dwelling out, sell it in one year, and pay off the mortgage. I say we have a 14 percent required return on equity, or an expected $3,500 each on our $25,000 individual equity investments. But you only require 10 percent, the overall expected rate of return on the dwelling itself, because you don't think use of a mortgage increases your required return on equity. That means you'll be satisfied with an expected return of $2,500. It's easy for us to achieve that outcome: whatever the result of our investment, I'll just pocket an extra $1,000 from your half of the investment as part of my share. You're happy, because you get the 10 percent expected rate of return you require, and so am I, because I earn a superior risk-adjusted rate of return, 18 percent instead of the market 14 percent. In fact, I'd even be willing to split the difference and take only $500 instead of $1,000 from your half. That would give us both a higher expected return than we require, you 12 percent ($3,000/$25,000) and me 16 percent ($4,000/$25,000). It's win-win, given your return requirements. After we cash out the first year's dwelling, let's do it again, but with more money next time."

Anyone willing to bear financial risk without reward can expect many such offers. Anyone who asks someone else to bear financial risk without reward will find few if any takers. That is why the more debt a company adds, the higher its cost of equity.

**Q5. Are mortgages the only everyday example of the effect of debt on the risk of equity?**

A5. No, any time someone uses debt to finance part an investment, the same risk magnification occurs. For example, if you buy stocks "on margin" -- by borrowing part of the money you use to buy them -- you have a higher expected rate of return, but more risk. You could illustrate this by attaching new labels to Figures 3 and 4 in the body of my evidence, say, so the "dwelling" became your stock portfolio and the "mortgage" became your margin debt. Of course, stocks are a lot more volatile than dwellings, in normal circumstances, so you'd be hard pressed to use 80 percent margin to buy stocks unless you offered additional security. If you did buy on margin, you'd have a higher expected rate of return, as in Figure B-1 (again, with the labels changed), but you'd be bearing a lot more risk, too. Imagine investing your retirement savings in a stock portfolio bought with as much margin as possible. If you were lucky, you could end up living very well in retirement. But you'd be taking a lot of risk of the opposite outcome, since your portfolio could decline by more than 100 percent of your initial investment.

The point is, exactly the same risk-magnifying effects happen when companies borrow to finance part of their investments.

## II. "BOTTOM LINE" IMPLICATIONS OF RESEARCH ON DEBT'S ACTUAL EFFECTS

**Q6. Does not your example still ignore important real-world considerations, such as taxes?**

A6. Yes, and considerable research has been done on such issues. Much of that research does look at taxes. Other parts address such issues as the risk of financial distress or bankruptcy, and the signals corporations send investors by the choice of how to finance new investments. The bottom line is that such factors complicate the picture without changing the basic conclusion.

**Q7. Nonetheless, please describe the potential impact of taxes. Start with why taxes may affect the appropriate capital structure.**

A7. Interest expense is tax-deductible for corporations. That increases the pool of cash the corporation gets to keep out of its operating earnings (i.e., its earnings before interest expense). With no debt, 100 percent of operating income is subject to taxes. With debt, only the equity part of the operating income is subject to taxes.

All else equal, the extra money kept from operating income increases the value of the corporation. The standard way to recognize that increase in value is to use an after-tax weighted-average cost of capital as a discount rate when valuing a company's operating cash flows.[25]

**Q8. Do personal taxes affect the value of debt, too?**

A8. Yes, but in the other direction. One offset to debt's tax benefits at the corporate level is its higher tax burden at the personal level. Investors care about the money they get to keep after all taxes are paid, and while the corporation saves taxes by opting for debt over equity, individuals pay more taxes on interest than on capital gains from equity (and for now, on dividends as well).

**Q9. Does anything else (i.e., other than taxes) matter?**

A9. Absolutely. "All else" does not remain equal as more debt is added. The more debt, the more the non-tax effects of debt offset the tax benefits. Other costs include such effects as a loss of flexibility, the possibility of sending negative signals to investors, and a host of costs and risks associated with the danger of financial distress.

**Q10. Does the tradeoff between the tax and non-tax effects of debt mean that firms have well-defined, optimal capital structures?**

A10. No, this sort of "tradeoff" model does not explain actual corporate behaviour. A substantial body of economic research confirms that real-world corporations act as if, after a moderate amount of debt is in place, the tax benefits of debt are not worth debt's other

[25] As noted in the body of my evidence and discussed in more detail below, the textbook after-tax weighted-average cost of capital used for this purpose equals the *market*-value weighted average of the cost of equity and the *after-tax,cur rent* cost of debt.

costs. In country after country and in industry after industry, the most profitable corporations in an industry tend to use the least debt. The research on this point is quite thorough, and the finding that the most profitable companies tend to use the least debt in a given industry is robust. Yet these are the companies with the most operating income to shield from taxes, who would benefit most if interest tax shields were truly valuable net of debt's other costs. They also presumptively are the best-managed on average (else why are they the most profitable?).

This means it is unrealistic to suppose that more debt is always better, or that greater tax savings due to higher interest expense always add value to the firm on balance.

**Q11. If the tradeoff model doesn't explain capital structure decisions by firms, is there a model that does?**

A11. No, not completely. Various alternative models to the tradeoff model exist (e.g., the "pecking order" hypothesis and "agency cost" explanations), but no theory has yet emerged as "the" explanation of capital structure. That very fact, however, has important implications for the overall effect of debt on the value of the firm.

**Q12. What does the absence of an agreed theory of capital structure in the financial literature imply about the overall effect of debt on the value of the firm?**

A12. The findings of theoretical and empirical research mean that within an industry, there is no well-defined optimal capital structure. Use of some debt does convey some value advantage in most industries, but that advantage is offset by other costs as firms add more debt.[26] The range of capital structures over which the value of the firm in any industry is maximized is wide and should be treated as flat. The location and level of that range, however, does vary from industry to industry, just as the overall cost of capital varies from industry to industry.

Figure B-2 illustrates the picture that emerges from the research. This figure shows the present value of an investment in each of four different industries. For simplicity, the investment is expected to yield $1.00 per year forever. For firms in relatively high-risk industries (Industry 1 in the graph, the lowest line), the $1.00 perpetuity is not worth much and any use of debt decreases firm value. For firms in relatively low-risk industries (Industry 4 in the graph), the perpetuity is worth more and substantial amounts of debt make sense. Industries 2 and 3 are intermediate cases.

[26] Note that if debt did increase the value of the firm materially, competition would tend to take that value away, since issuing debt is an easy-to-copy competitive strategy. Prices would fall as firms copied the strategy, lowering operating earnings and passing the net tax advantages to debt through to customers (just as happens under rate regulation). Therefore, if also there were a narrow range of optimal capital structures within an industry, competition would drive all firms in the industry to capital structures within that range. This does not happen in practice, which contradicts one or both of the assumptions, i.e., (1) that debt adds material value on balance, and/or (2) that there is a narrow range of optimal capital structures.

**Illustrative Value Curves for Four Industries of Different Business Risk, plus Maximum Possible Value Due to Net Tax Advantage of Debt for Industry 4**

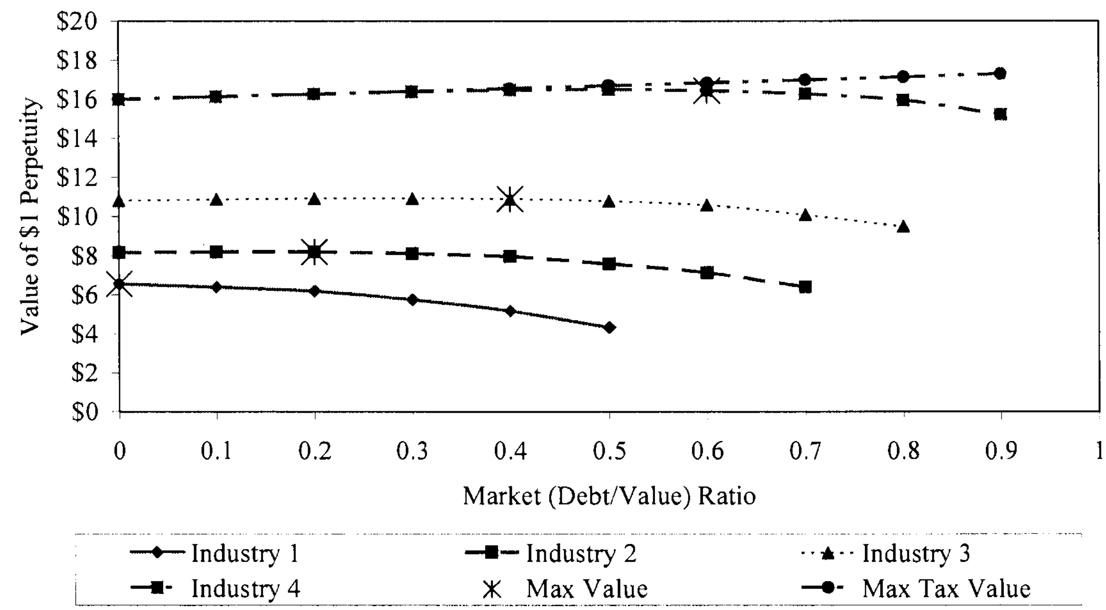


**Figure B-2**

The maximum net rate at which taxes can increase value in this figure equals 10 percent of interest expense, representing a balance between the corporate tax advantage to debt and the personal tax disadvantage.[27] The figure plots the maximum possible impact of taxes on value as a separate line, starting at the all-equity value of the lowest-risk industry (Industry 4).

Figure B-2 identifies a particular point as the maximum value on each of the four curves. However, the research shows that reliable identification of this maximum point, except in the extreme case where no debt should be used, is impossible. In accord with the

[27] The 10 percent value is based on the Canadian trade-off between personal and corporate taxes.

research, the graph is prepared so that in none of the industries does a change in capital structure make much difference near the top of the curve. Even Industry 4, which increases in value at the maximum rate as quite a lot of debt is added, eventually must reach a broad range where changes in the debt ratio make little difference to firm value, given the research. For Industry 4, debt makes less than a 2 percent difference in the total value of the firm for debt-to-value ratios between 40 and 70 percent. (While these particular values are illustrative, numbers of this order of magnitude are the only ones consistent with the research.)

**Q13. What does this imply for the overall cost of capital?**

A13. Figure B-3 plots the after-tax weighted-average costs of capital ("ATWACCs") that correspond to the value curves in Figure B-2. This picture just turns Figure B-2 upside down.[28] All the same conclusions remain, except that they are stated in terms of the overall cost of capital instead of the overall firm value. In particular, except for high-risk industries, the overall cost of capital is essentially flat across a broad middle range of capital structures for each industry, which is the only outcome consistent with the research. For Industry 4, for example, the ATWACC changes by less than 10 basis points for debt-to-value ratios between 40 and 70 percent.

[28] Note that the actual estimated ATWACC at higher debt ratios will tend to underestimate the ATWACC that corresponds to the value curves in Figure B-2, which are depicted in Figure B-3, and so will tend to overestimate the value of debt to the firm. The reason is that some of the non-tax effects of excessive debt, such as a loss of financial flexibility, may be hard to detect and not show up in cost of capital measurement. Also, the value of the firm will fall at high debt ratios for reasons that can be entirely independent of the cost of capital, strictly defined. Therefore, the true ATWACC for project valuation purposes, at least at high debt ratios, is higher than the simple average of an industry sample of ATWACCs, but this refinement cannot be made with available estimation techniques. This conclusion carries over to rate regulation, too.

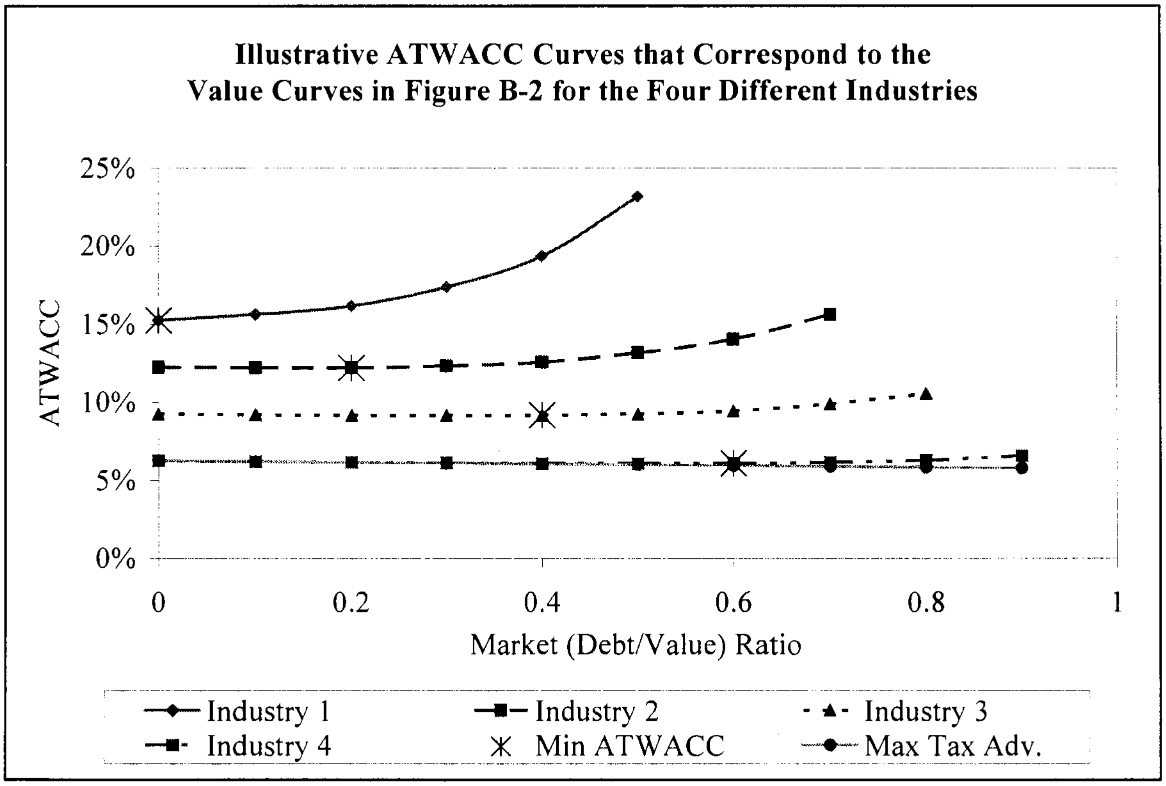


**Figure B-3**

**Q14. How does this discussion relate to estimation of the right cost of equity for ratemaking purposes?**

A14. When an analyst estimates the cost of equity for a sample of companies, s/he does so at the sample's actual market-value capital structure. That is, the sample evidence corresponds to ATWACCs that are already out somewhere in the broad middle range in which changes in the debt ratio have little or no impact on the overall value of the firm or the ATWACC.

An analyst therefore should assume the ATWACCs for the sample companies are literally flat. This assumption always provides the exact tradeoff between the cost of equity and capital structure at the literal minimum of the company's ATWACC curve. The research shows that this minimum is actually a broad, flat region, as depicted above. If the company happens to be somewhat to one side or the other of the literal minimum within this region, the recommended procedure may lead to a very small understatement or overstatement of the amount that the cost of equity will change as capital structure changes. The degree of this under- or overstatement, however, is trivial compared to the inherent uncertainty in estimating the cost of equity in the first place. Otherwise, the financial research would have found very different results about the existence of a narrowly defined optimal capital structure.

**Q15. Can you provide an overview of this research?**

A15. Yes, and I do so immediately below. But first I must caution that there are certainly dozens, and perhaps hundreds of scholarly papers on this topic. The next section describes key historical papers in the literature and a good sampling of relevant recent research, but I cannot and do not claim it is comprehensive.

## III. AN OVERVIEW OF THE ECONOMIC LITERATURE

**Q16. What is the focus of the economic literature on the effects of debt?**

A16. The economic literature focuses on the effects of debt on the value of a firm. The standard way to recognize one of these effects, the impact of the fact that interest expense is tax-deductible, is to discount the all-equity after-tax operating cash flows generated by a firm or an investment project at a weighted average cost of capital, typically known in textbooks as the "WACC." The textbook WACC equals the *market*-value weighted average of the cost of equity and the *after-tax*, *current* cost of debt. However, rate regulation in North America has a legacy of working with another weighted-average cost of capital, the *book*-value weighted average of the cost of equity and the *before-tax*, *embedded* cost of debt. Accordingly, in regulatory settings it's useful to refer to the textbook WACC as the "ATWACC," or after-tax weighted-average cost of capital. I follow that practice here.

**Q17. What is the implication of the literature's focus for this section?**

A17. Since the literature focuses on the overall effect of debt on the value of the firm, a discussion summarizing that literature must do so, also. A principal goal of the appendix is to translate the literature's findings on debt's effects on firm value into a procedure to calculate the equity ratio that is consistent with a sample's risk-return evidence and a particular formula rate of return on equity. For these reasons, much of the discussion in this first section focuses on the overall cost of capital, i.e., the ATWACC. The next section translates these findings into specific deemed equity ratio terms.

**Q18. How is this section of the appendix organized?**

A18. It starts with the tax effects of debt. It then turns to other effects of debt.

### A. TAX EFFECTS

**Q19. What are the main threads of the literature on the tax effects of debt?**

A19. Three seminal papers define the main threads of this literature. The first assumes no taxes and risk-free debt. The second adds corporate income taxes. The third adds personal income taxes.

### 1. Base Case: No Taxes, No Risk to High Debt Ratios

**Q20. Please start by explaining the simplest case of the effect of debt on the value of a firm.**

A20. The "base case," no taxes and no costs to excessive debt, was worked out in a classic 1958 paper by Franco Modigliani and Merton Miller, two economists who eventually won Nobel Prizes in part for their body of work on the effects of debt.[29] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt plus equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

In this case, issuing debt merely divides the same set of cash flows into two pools, one for bondholders and one for shareholders. If the divided pools have different priorities in claims on the cash flows, the risks and costs of capital will differ for each pool. But the risk and overall cost of capital of the entire firm, the sum of the two pools, is constant regardless of the debt ratio. That means,

$$r^*_1 = r_{A1} \qquad \text{(B-1a)}$$

where $r^*_1$ is the overall after-tax cost of capital at any particular capital structure and $r_{A1}$ is the all-equity cost of capital for the firm. (The "1" subscripts distinguish these quantities in the case where there are no taxes from subsequent equations that consider first corporate

[29] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48: 261-297 (June 1958).

and then both corporate and personal taxes.) With no taxes and no risk to debt, the overall cost of capital does not change with capital structure.

This implies that the right formula to relate the overall cost of capital to the component costs of debt and equity is

$$r_{E1} \times (E/V) + r_D \times (D/V) = r^*_1 \qquad \text{(B-1b)}$$

with the overall cost of capital ($r^*$) on the *right* side, as the *independent* variable, and the costs of equity ($r_E$) and debt ($r_D$) on the left side, as *dependent* variables determined by the overall cost of capital and by the capital structure (i.e., the shares of equity (E) and debt (D) in overall firm value (V=E+D)) that the firm happens to choose. Note that if equation (B-1a) were correct, the equation that solved it for the cost of equity would be,

$$r_{E1} = r^*_1 + (r^*_1 - r_D) \times (D/E) \qquad \text{(B-1c)}$$

Note also that (D/E) gets exponentially higher in this equation as the debt-to-value ratio increases.[30] Therefore Equation (B-1c) has the property emphasized in the body of my evidence, that the cost of equity grows at an ever-increasing rate as you add more and more debt.

[30] For example, at 20-80, 50-50, and 80-20 debt-equity ratios, (D/E) equals, respectively, (20/80) = 0.25, (50/50) = 1.0, and (80/20) = 4.0. The extra 30 percent of debt going from 20-80 to 50-50 has much less impact on (D/E) [i.e., by moving it from 0.25 to 1.0] than the extra 30 percent of debt going from 50-50 to 80-20 [i.e., by moving it from 1.0 to 4.0]. Since the cost of equity equals a constant risk premium times the debt-equity ratio, the cost of equity grows ever more rapidly as you add more and more debt.

### 2. Corporate Tax Deduction for Interest Expense

**Q21. What happens when you add corporate taxes to the discussion?**

A21. If corporate taxes exist with risk-free debt (and if only taxes at the corporate level matter, not taxes at the level of the investor's personal tax return), the initial conclusion changes. Debt at the corporate level reduces the company's tax liability by an amount equal to the marginal tax rate times interest expense. All else equal, this will add value to the company because more of the operating cash flows will end up in the hands of investors as a group. To illustrate this point, consider the example in Table B-1.

**Table B-1**
**Effect of Corporate Tax Deduction for Interest Expense**

| | Without Debt | With Debt |
|---|---|---|
| **Pre-Tax Operating Income** | $1,000 | $1,000 |
| **- Interest Expense** | - 0 | - 200 |
| **= Pre-Tax Equity Income** | $1,000 | $800 |
| **- Taxes @ 35%** | - 350 | - 280 |
| **= After-Tax Equity Income** | $650 | $520 |
| **+ Interest to Bondholders** | + 0 | + 200 |
| **= Income to All Investors** | $650 | $720 |

A company without debt starts out with $1,000 in pre-tax operating income and pays taxes at a 35 percent rate. It has ($1,000×0.35) = $350 in taxes and ($1,000-$350) = $650 available for investors. If it now issues debt that has $200 in interest expense, its taxes fall to [($1,000-$200)×0.35] = $280, and it has ($1,000-$280) = $720 available for investors as a group. The tax advantage to the use of debt is ($720-$650) = $70, or 35 percent of the $200 in interest.

Thus, if only corporate taxes mattered, interest would add cash to the firm equal to the corporate tax rate times the interest expense. This increase in cash would increase the value of the firm, all else equal. In cost of capital terms, it would reduce the overall cost of capital.

*How much* the value of the firm would rise and *how far* the overall cost of capital would fall would depend in part on how often the company adjusts its capital structure, but this is a second-order effect in practice. (The biggest effect would be if companies could issue riskless perpetual debt, an assumption Profs. Modigliani and Miller explored in 1963, in the second seminal paper;[31] this assumption could *not* be true for a real company.) Prof. Robert A. Taggart provides a unified treatment of the main papers in this literature and shows how various cases relate to one another.[32] Perhaps the most useful set of benchmark equations for the case where only corporate taxes matter are:

$$r^*_2 = r_{A2} - r_D \times t_C \times (D/V) \qquad \text{(B-2a)}$$

$$r_{E2} \times (E/V) + r_D \times (D/V) \times (1 - t_C) = r^*_2 \qquad \text{(B-2b)}$$

which imply for the cost of equity,

$$r_{E2} = r_{A2} + (r_{A2} - r_D) \times (D/E) \qquad \text{(B-2c)}$$

where the variables have the same meaning as before but the "2" subscripts indicate the case that considers corporate but not personal taxes.

Note that Equation (B-2a) implies that when only corporate taxes matter, the overall after-tax cost of capital declines steadily as more debt is added, until it reaches a minimum

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[31] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

[32] Robert A. Taggart, Jr., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management* 20: 8-20 (Autumn 1991)

at 100 percent debt (i.e., when D/V = 1.0). Note also that Equation (B-2c) still implies an exponentially increasing cost of equity as more and more debt is added. In fact, except for the subscript, Equation (B-2c) looks just like Equation (B-1c).

However, whether any value is added and whether the cost of capital changes at all also depends on the effect of taxes at the personal level.

### 3. Personal Tax Burden on Interest Expense

**Q22. How do personal taxes affect the results?**

A22. Ultimately, the purpose of investment is to provide income for consumption, so personal taxes affect investment returns. For example, in the U.S., municipal bonds have lower interest rates than corporate bonds because their income is taxed less heavily at the personal level. In general, capital appreciation on common stocks is taxed less heavily than interest on corporate bonds because (1) taxes on unrealized capital gains are deferred until the gains are realized, and (2) the capital gains tax rate is lower. Dividends are taxed less heavily than interest, also. The effects of personal taxes on the cost of common equity are hard to measure, however, because common equity is so risky.

Professor Miller, in his Presidential Address to the American Finance Association,[33] explored the issue of how personal taxes affect the overall cost of capital. The paper pointed out that personal tax effects could offset the effect of corporate taxes entirely. To see how this might work, consider the after-corporate-tax, after-personal-tax investor returns of the firm in Table B-2, with and without debt.

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[33] Merton H. Miller, "Debt and Taxes," *The Journal of Finance*, 32: 261-276 (May 1977), the third of the seminal papers mentioned earlier.

**Table B-2**
**Combined Effect of Corporate and Personal Taxes**

| | Without Debt | With Debt |
|---|---|---|
| **Pre-Tax Operating Income** | $1,000 | $1,000 |
| **– Interest Expense** | - 0 | - 200 |
| **= Pre-Tax Equity Income** | $1,000 | $800 |
| **– Taxes @ 35%** | - 350 | - 280 |
| **= After-Tax Equity Income** | $650 | $520 |
| **– Personal Taxes @ 7.7%** | - 50 | - 40 |
| **= After-All-Tax Equity Income** | $600 | $480 |
| **+ Interest to Bondholders** | + 0 | + 200 |
| **– Personal Taxes @ 40%** | - 0 | - 80 |
| **= Total After-All-Tax Income** | $600 | $600 |

Suppose the corporate tax rate were 35 percent, the effective personal tax rate on the marginal investors holding corporate debt were 40 percent, and the effective personal tax rate on the marginal investors holding common equity were only 7.7 percent, representing a blend of the rates on dividends and on the present value of future capital gains when finally realized. Then corporate taxes for an all-equity firm with pre-tax operating income of $1,000 would be ($1,000×0.35) = $350, as above, leaving ($1,000–$350) = $650 in after-corporate-tax earnings to be distributed as dividends or retained to support future capital gains. Personal taxes on that amount at the effective marginal personal tax rate on equity would be ($650×0.077) = $50. The after-all-tax cash flow to the marginal investors in an all-equity firm would be ($1,000–$350–$50) = $600.

Now suppose the firm issues debt with $200 in interest expense, as before. Corporate taxes again fall to [($1,000-$200)×0.35] = $280, and the firm has ($1,000–$280) = $720 to distribute to investors. After all taxes, equityholders keep $480 of that, and bondholders keep \$120, for the same \$600 total. Or to calculate it another way, the personal tax burden on all investors equals the sum of that on debt and on equity, or {(\$200×0.40) + [(\$720-\$200)×0.077)]} = (\$80 + \$40) = \$120. The after-all-tax cash flow to the investors in the levered-equity firm would be (\$1,000-\$280-\$120) = \$600, again the same as for the all-equity firm. The tax advantage to use of debt at the corporate level would vanish entirely at the personal level under these conditions.

**Q23. Is it likely that the effect of personal taxes will completely neutralize the effect of corporate taxes?**

A23. No. These conditions seem pretty unlikely, if they require only a 7.7 percent effective personal tax rate on equity. However, personal taxes are important even if they do not make the corporate tax advantage on interest vanish entirely. Capital gains and dividend tax advantages definitely convey some personal tax advantage to equity, and even a partial personal advantage to equity reduces the corporate advantage to debt. (Section III of this appendix explores the degree of offset in more detail using actual tax rates.)

The Taggart paper explores the case of a partial offset, also. With personal taxes, the risk-free rate on the security market line (Figure 1 in Dr. Vilbert's evidence) is the after-personal-tax rate, which must be equal for risk-free debt and risk-free equity.[34] Therefore, the pre-personal-tax risk-free rate for equity will generally not be equal to the pre-personal-tax risk-free rate for debt. In particular, $r_{fE} = r_{fD} \times [(1-t_D)/(1-t_E)]$, where $r_{fE}$ and $r_{fD}$ are the risk-free costs of equity and debt and $t_E$ and $t_D$ are the personal tax rates for

[34] As Prof. Taggart notes (his footnote 9), it is not necessary that a specific, risk-free equity security exist as long as one can be created synthetically, through a combination of long and short sales of traded assets. Such constructs are a common analytical tool in financial economics.

equity and debt, respectively. In terms of the cost of debt, the Taggart paper's results imply that a formal statement of these effects can be written as:[35]

$$r^*_3 = r_{A3} - r_D \times t_N \times (D/V) \qquad \text{(B-3a)}$$

$$r_{E3} \times (E/V) + r_D \times (D/V) \times (1 - t_C) = r^*_3 \qquad \text{(B-3b)}$$

which imply

$$r_{E3} = r_{A3} + \{r_{A3} - r_D \times [(1 - t_D)/(1 - t_E)]\} \times (D/E) \qquad \text{(B-3c)}$$

Note that the first case above, $t_E$ = 7.7 percent and $t_D$ = 40 percent, implies $[(1 - t_D)/(1 - t_E)] = 0.65 = (1 - t_C)$. That corresponds to Miller's 1977 paper, in which the net personal tax advantage of equity fully offsets the net corporate tax advantage of debt. Note also that in that case, $t_N = 0$.[36] Therefore, if the personal tax advantage on equity fully offsets the corporate tax advantage on debt, Equation (B-3a) confirms that the overall after-tax cost of capital is a constant.

However, it is unlikely that the personal tax advantage of equity fully offsets the corporate tax advantage of debt. If not, and if taxes were all that mattered (i.e., if there were no other costs to debt), the overall after-corporate-tax cost of capital would still fall as debt was added, just not as fast. How fast it falls would depend chiefly on the net corporate-over-personal tax advantage of debt (and secondarily on how often the company

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[35] The net all-tax effect of debt on the overall cost of capital, $t_N$, equals $\{[t_C + t_E - t_D - (t_C \times t_E)] / (1 - t_E)\}$, where $t_D$ is the personal tax rate on debt, as before. This measure of net tax effect is designed for use with the cost of debt in Equation (B-3a), which seems more useful in the present context. The Taggart paper works with a similar measure, but one which is designed for use with the cost of risk-free equity in the equivalent Taggart equation.

[36] In the above example, $t_N = \{[0.35 + 0.077 - 0.4 - (0.35 \times 0.077)] / (1.0 - 0.077)\} = 0.0/0.963 = 0$.

readjusts its capital structure to the "normal" or "target" level). Even absent a complete offset, personal tax effects still serve to reduce the corporate tax advantage of debt.

Finally, note that the overall after-tax cost of capital, Equation (B-3b), still uses the corporate tax rate even when personal taxes matter. Equations (B-2b) and (B-3b) both correspond to the usual formula for the ATWACC. Personal taxes affect the way the cost of equity changes with capital structure -- Equation (B-3c) -- but not the formula for the overall after-tax cost of capital given that cost of equity.

### B. NON-TAX EFFECTS

**Q24. Please describe the non-tax effects of debt.**

A24. If debt is truly valuable, firms should use as much as possible, and competition should drive firms in a particular industry to the same, optimal capital structure for the industry. If debt is harmful on balance, firms should avoid it. As I discuss below, neither picture corresponds to what we actually see. A large economic literature has evolved to try to explain why.

Part of the answer clearly are the costs of excessive debt. Here the results cannot be reduced to equations, but they are no less real for that fact. As companies add too much debt, the costs come to outweigh the benefits. Too much debt reduces or eliminates financial flexibility, which cuts the firm's ability to take advantage of unexpected opportunities or weather unexpected difficulty. Use of debt rather than internal financing may be taken as a negative signal by the market.

Also, even if the company is generally healthy, more debt increases the risk that a bad year will imply the company cannot use all of the interest tax shields when anticipated.

As debt continues to grow, this problem grows worse and others crop up. Managers begin to worry about meeting debt payments instead of making good operating decisions. Suppliers are less willing to extend trade credit, and a liquidity shortage can translate into lower operating profits. Ultimately, the firm might have to go through the costs of bankruptcy and reorganization. Collectively, such factors are known as the costs of "financial distress."[37]

The net tax advantage to debt, if positive, is affected by costs such as a growing risk that the firm might have to bear the costs of financial distress. First, the expected present value of these costs offsets the value added by the interest tax shield. Second, since the likelihood of financial distress is greater in bad times when other investments also do poorly, the possibility of financial distress will increase the risks investors bear. These effects increase the variability of the value of the firm. Thus, firms that use too much debt can end up with a higher overall cost of capital than those that use none.

Other parts of the answer include the signals companies send to investors by the decision to issue new securities, and by the type of securities they issue. Other threads of the literature explore cases where management acts against shareholder interests, or where management attempts to "time" the market by issuing specific securities under different conditions. For present purposes, the important point is that no theory, whether based on taxes or on some completely different issue, has emerged as "the" explanation for capital structure decisions by firms. Nonetheless, despite the lack of a single "best" theory, there is a great deal of relevant empirical research.

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[37] See, for example, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, 8th Ed., New York: Irwin McGraw-Hill (2005), pp. 476-90.

**Q25. What does that research show?**

A25. The research does not support the view that debt makes a material difference in the value of the firm, at least not once a modest amount of debt is in place. If debt were truly valuable, competitive firms should use as much as possible without producing financial distress, and competitive firms that use less debt ought to be less profitable. The research shows exactly the opposite.

For example, Kestler[38] found that firms in the same industry in both the U.S. and Japan do not band around a single, "optimal" capital structure, and the most profitable firms are the ones that use the *least* debt. This finding comes despite the fact that both countries at the time (unlike Canada) had fully "classical" tax systems, in which dividends are taxed fully at both the corporate and personal level.[39] Wald[40] confirms that high profitability implies low debt ratios in France, Germany, Japan, the U.K., and the U.S. Booth *et al.* find the same result for a sample of developing nations.[41] Fama and French[42] analyze over 2000 firms for 28 years (1965-1992, inclusive) and conclude, "Our tests thus

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38 Carl Kester, "Capital and Ownership Structure: A Comparison of United States and Japanese Manufacturing Concerns," *Financial Management*, 15:5-16, (Spring, 1986).

39 The U.S. currently has an exception to this long-standing policy, under which dividends bear a lower tax rate than interest. However, no such exception was in place when the research described in this appendix was performed.

40 John K. Wald, "How Firm Characteristics Affect Capital Structure: An International Comparison," *Journal of Financial Research*, 22:161-167 (Summer 1999).

41 Laurence Booth *et al.*, "Capital Structures in Developing Countries," *The Journal of Finance* Vol. LVI (February 2001), pp. 87-130, finds at p. 105 that "[o]verall, the strongest result is that profitable firms use less total debt. The strength of this result is striking ..."

42 Eugene F. Fama and Kenneth R. French, "Taxes, Financing Decisions and Firm Value," *The Journal of Finance*, 53:819-843 (June 1998).

produce no indication that debt has net tax benefits."[43] A recent paper by Graham[44] carefully analyzes the factors that might have led a firm not to take advantage of debt. It confirms that a large proportion of firms that ought to benefit substantially from use of additional debt, including large, profitable, liquid firms, appear not to use it "enough."

This research leaves us with only three options: either (1) apparently good, profit-generating managers are making major mistakes or deliberately acting against shareholder interests, (2) the benefits of the tax deduction are less than they appear, or (3) the non-tax costs to use of debt offset the potential tax benefits. Only the first of these possibilities is consistent with the view that the tax deductibility of debt conveys a material cost advantage. Moreover, if the first explanation were interpreted to mean that good managers are deliberately acting against shareholder interests, it would require the additional assumption that their competitors (and potential acquirers) let them get away with it.

**Q26. Are there any explanations in the financial literature for this puzzle other than stupid or self-serving managers at the most profitable firms?**

A26. Yes. For example, Stewart C. Myers, a leading expert on capital structure, made it the topic of his Presidential Address to the American Finance Association.[45] The poor performance of tax-based explanations for capital structure led him to propose an entirely

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43 *Ibid.*, p. 841.

44 John R. Graham, "How Big Are the Tax Benefits of Debt," *The Journal of Finance*, 55:1901-1942 (October 2000)

45 Stewart C. Myers, "The Capital Structure Puzzle," *The Journal of Finance*, 39: 575-592 (1984). See also S. C. Myers and N. S. Majluf, "Corporate Financing Decisions When Firms Have Information Investors Do Not Have," *Journal of Financial Economics* 13:187-222 (June 1984).

different mechanism, the "pecking order" hypothesis. This hypothesis holds that the net tax benefits of debt (i.e., corporate tax advantage over personal tax disadvantage) are at most of a second order of importance relative to other factors that drive actual debt decisions.[46] Similarly, Baker and Wurgler (2002)[47] observe a strong and persistent impact that fluctuations in market value have on capital structure. They argue that this impact is not consistent with other theories. The authors suggest a new capital structure theory based on market timing -- capital structure is the cumulative outcome of attempts to time the equity market.[48] In this theory, there is no optimal capital structure, so market timing financing decisions just accumulate over time into the capital structure outcome. (Of course, this theory only makes sense if investors do not recognize what managers are doing.)

**Q27. Do inter-firm differences within an industry explain the wide variations in capital structure across the firms in an industry?**

A27. No. Any such view is flatly contradicted by the empirical research. As already noted, it has long been found that the most profitable firms in an industry, i.e., those in the best position to take advantage of debt, use the least.[49] The recent Graham paper very carefully

[46] See also Stewart C. Myers, "Still Searching for Optimal Capital Structure," *Are the Distinctions Between Debt and Equity Disappearing?*, R.W. Kopke and E. S. Rosengren, eds., Federal Reserve Bank of Boston. (1989).

[47] Malcolm Baker and Jeffrey Wurgler, "Market Timing and Capital Structure," *The Journal of Finance* 57:1-32 (2002).

[48] *Ibid.*, p. 29.

[49] For example, Kestler, *op. cit.* and Wald, *op. cit.*

examines differences in firm characteristics as possible explanations for why firms use "too little" debt and concludes that such differences are *not* the explanation: firms that ought to benefit substantially from more debt by all measurable criteria, if the net tax advantage of debt is truly valuable, voluntarily do not use it.[50]

Nor does the research support the view that firms are constantly trying to adjust their capital structures to optimal levels. Additional research on the pecking order hypothesis demonstrates that firms do not tend towards a target capital structure, or at least do not do so with any regularity, and that past studies that seemed to show the contrary actually lacked the power to distinguish whether the hypothesis was true or not.[51] In the words of the Shyam-Sunder - Myers paper (at p. 242), "If our sample companies did have well-defined optimal debt ratios, it seems that their managers were not much interested in getting there."[52]

[50] While not contradicting Graham's finding that differences in firm characteristics do not explain capital structure differences, Nengjiu Ju, Robert Parrino, Allen M. Poteshman, and Michael S. Weisbach, "Horses and Rabbits? Trade-Off Theory and Optimal Capital Structure," *Journal of Financial and Quantitative Analysis*) 40:259-281 (June 2005), looks at the issue in another way. This paper uses a dynamic rather than static model to analyze the tradeoff between the tax benefits of debt and the risk of financial distress. It finds that bankruptcy costs by themselves are enough to explain observed capital structures, once dynamic effects are considered. This simply means debt is not as valuable as the traditional static analysis, of the sort used by Graham and many others, implies.

[51] Lakshmi Shyam-Sunder and Stewart C. Myers, "Testing static tradeoff against pecking order models of capital structure," *Journal of Financial Economics* 51:219-244 (February 1999).

[52] See also the Winter 1995 issue of the *Journal of Applied Corporate Finance* 7, No. 4, which has a series of articles on what might explain capital structure, given that the static tradeoff approach does not.

### C. COMBINED EFFECTS

**Q28. Please summarize the implications of this literature for the combined impact of the tax and non-tax effects of debt.**

A28. The above results are not *theory*, they are empirical *fact*. The most profitable firms do not behave as if debt makes any material difference to value, and competition does not force them into an alternative decision, as it would if debt were genuinely valuable. As noted in the main body of my evidence, the explanation that fits the facts and the research is that within an industry, there is no well-defined optimal capital structure. Use of some debt does convey an advantage in most industries, but that advantage is offset by other costs as firms add more debt. The range of capital structures over which the value of the firm in any industry is maximized is wide and should be treated as flat. The location and level of that range, however, does vary from industry to industry, just as the overall cost of capital varies from industry to industry. To conclude that more debt does add more value, once the firm is somewhere in the normal range for the industry, is to conclude that corporate management in general is either blind to an easy source of value or otherwise incompetent, and that their competitors let them get away with it.

**Q29. Does this complete Appendix B?**

A29. Yes, it does.

**WRITTEN EVIDENCE**

**OF**

**PAUL R. CARPENTER**

**FOR**

**UNION GAS LIMITED**

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

January 2006

WRITTEN EVIDENCE OF
PAUL R. CARPENTER

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WRITTEN EVIDENCE OF
PAUL R. CARPENTER

## I. OVERVIEW/SUMMARY

**Q1. Please state your name, address and position.**

A1. My name is Paul R. Carpenter. I am a Principal of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Massachusetts, Washington D.C., San Francisco, Brussels, Belgium and London, England. My office is located at 44 Brattle Street, Cambridge, Massachusetts 02138.

**Q2. Will you briefly describe your educational background and professional qualifications?**

A2. Yes. I am an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. I received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for twenty years. I frequently have testified before federal, state and Canadian regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, I have advised governments and regulatory bodies on the structure of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the governments of, and regulators in, Greece, Ireland, the Netherlands, New Zealand and Australia.

For at least 15 years I have been extensively involved in the evaluation of the economics and regulation of the natural gas industry in North America. In Canada, I have advised pipeline companies and have previously testified before the National Energy Board ("NEB") and the Alberta Energy and Utilities Board on matters relating to pipeline competition and capacity expansion, including the Alliance Pipeline Ltd. certification proceeding. I gave evidence on business risk previously before the NEB in the multi-pipeline cost of capital case, on behalf of Foothills Pipe Lines, and in more recent NEB proceedings on behalf of TransCanada PipeLines Limited. This is the first time that I have appeared before the Ontario Energy Board ("OEB" or "Board"). Further details of my educational and professional background, as well as a listing of my publications, are provided in my curriculum vitae, which is appended to this testimony as Attachment A.

**Q3. What is the purpose of your evidence in this proceeding?**

A3. My evidence evaluates whether there has been a change in Union Gas Limited's ("Union's") business risk since 1998 that would warrant a change in the deemed equity thickness authorized by the Board for Union. In addition, I evaluate Union's business risk relative to the sample of U.S. local distribution companies ("LDC's") employed by Dr. Michael Vilbert in his evidence.

**Q4. What is the basis for the 1998 reference date for this evaluation?**

A4. It is my understanding that 1998 corresponds to the last time the Board approved a change in Union's equity thickness that involved an evaluation of Union's business risk. In its most recent 2004 decision involving Union's cost of capital, the Board stated that it only evaluated changes in capital market conditions, and not business risk.[1]

**Q5. Could you summarize your conclusions?**

A5. Yes. My analysis indicates that equity investors would consider investment in Union to be significantly more risky today than it was in 1998. I have identified five sources of this increased risk:

1) The business risk of Union's gas distribution services have increased because they are now exposed to additional uncertainty due to changes in the commodity market for natural gas. The commodity market environment has changed markedly from the pre-1998 days of constrained pipeline outlet capacity from Western Canada and low wholesale prices to today's world in which Canadian prices are now "connected" to the rest of the North American market. In addition, Union and its customers are now facing extremely high and volatile prices that are beginning to be reflected in

[1] Ontario Energy Board, Decision and Order in the Matter of Applications By Union Gas Limited and Enbridge Gas Distribution Inc. for a Review of the Board's Guidelines for Establishing Their Respective Return on Equity, RP-2002-0158, January 16, 2004, paragraph 114.

declining gas usage per customer and increasing customer elasticity of demand. Industrial demand for gas, in particular, is susceptible to the high and volatile wholesale price regime. More uncertain future utilization of Union's distribution assets translates to higher business risks.

2) Union's distribution and transportation assets are now at an increased risk of bypass by competitive suppliers than they were in 1998. This increased risk is indicated by the increased uncertainty surrounding the future application of Board policy toward bypass as reflected in the Board's recent approval of GEC's application to build a bypass pipeline as well as Union's application to serve the same facility.
3) The market risks associated with new gas-fired power generation demand in Ontario are currently very uncertain as to the extent of new capacity that might be required, when it will require new gas infrastructure, the competition to provide that infrastructure and its associated capital requirements.
4) The business risks of Union's storage and transportation business have increased since 1998 because competition for that business has increased. This increased competition is reflected in the entry into the market by third-party storage suppliers, and by the decline in the remaining duration of Union's existing storage and transportation contracts. At the same time, potential but uncertain market growth is requiring Union to make significant capital expenditures to expand its transportation system in order to compete to provide these services.
5) Finally, there is significant uncertainty as to the future regulatory environment in which Union's storage and transportation assets will be operated. This is best reflected in the myriad of issues before the Board in the Natural Gas Forum process.

Primarily as a result of Union's competitive exposure in its transportation and storage business, I conclude that Union is more risky than the portfolio of gas LDC's used by Dr. Vilbert in his evidence.

**Q6. How is the rest of your evidence organized?**

A6. I begin by discussing the concept of business risk and how it relates to the cost of capital for a rate regulated firm. Then I describe the business risk environment in which Union operates in terms of each of the elements of business risk and Union's major business segments. Finally, I evaluate whether there have been significant changes in those risks since the Board last evaluated the issue in 1998.

## II. DETERMINANTS OF BUSINESS RISK AND THE COST OF CAPITAL

**Q7. How does one define business risk in the context of a company's cost of capital?**

A7. Business risk in the context of a company's cost of capital is the uncertainty in the income earning capability of the firm's assets that investors in the company's equity are exposed to over the economic lifetime of the assets. Business risk has been traditionally subdivided into market demand, supply, regulatory and operating risks.[2] Financial risk is dealt with separately in the analysis of Drs. Kolbe and Vilbert.

**Q8. What kinds of risks matter the most in evaluating a company's business risk from a cost of capital perspective?**

A8. The risks that matter the most from an equity investor's perspective are those that cannot be diversified away through the holding of a broad portfolio of securities. Risks that are hard to diversify are those that are generally correlated with the level of (and changes in) general economic activity. Such risks are referred to as "systematic." Broadly speaking, systematic risks associated with the gas distribution business include uncertainties in the demand for, and supply of, distribution services that are affected by changes in economic activity, including incomes and prices.

**Q9. How does the fact that a company itself may be comprised of a diversified portfolio of businesses affect the evaluation of a company's business risk?**

A9. Investors in a company that contains a diversified set of businesses will evaluate the total business risk of the company based on the weighted average risk of the portfolio of assets that makes up the company, where the weights are the market value shares of the individual businesses in the overall company portfolio. Investors will not view a

[2] National Energy Board, Reasons for Decision, TransCanada Pipelines Limited, RH-4-2001, June 2002, page 13.

company as less risky simply because the company has chosen to own a diversified set of assets. This is because investors themselves can always choose to diversify within their own investment portfolios, and therefore no additional risk-reduction value is assigned to a company that chooses to diversify.

**Q10. How does rate regulation affect a company's business risk?**

A10. On the one hand, rate regulation reduces a company's business risk if it provides equity investors some assurance that a fair return on and of capital will be earned over the lifetime of the firm's assets. On the other hand, regulation may enhance a company's business risk if investors perceive that there is uncertainty in the future regulatory treatment of the firm's businesses. That is why regulatory risk is traditionally evaluated as a separate component of business risk. While the equity securities of rate regulated firms are generally perceived as relatively stable, low-risk investments, the greater exposure of such firms to competition from other regulated and unregulated businesses has changed that perception somewhat in recent years, particularly in the energy utility sector.

## III. UNION'S BUSINESS RISK ENVIRONMENT

**Q11. How would you characterize Union's assets from a business risk perspective?**

A11. While a majority of Union's assets are devoted to the provision of traditional gas distribution services to residential, commercial and industrial customers, approximately 22 percent of Union's assets are currently devoted to the provision of storage and transmission services.[3] The latter are important enough, and subject to different risk factors than traditional gas distribution, that I have treated them separately in the analysis that follows.

**Q12. How does Union's gas distribution business subdivide the general service market in terms of customer classes?**

[3] On a functional basis, approximately 38 percent of Union's assets are composed of storage and transmission facilities.

A12. Union serves over 1.2 million customers. This general service market subdivides into residential, commercial and industrial classes. The residential class accounts for about 91 percent of customers and 56 percent of total throughput volumes, while the commercial and industrial classes account for 9 percent of customers and 44 percent of throughput. Union is forecasting total general service throughput in 2007 to be 5,249 $10^6m^3$, which represents a slight decline in its weather-normalized total throughput from 2004. The decline in forecast throughput is attributed to a decline in use per customer ("NAC" or "Normalized Average Consumption") of about 1.6 percent per year, a decline in light industrial consumption, and to the impact of Union's DSM plans.

**Q13. How does Union earn income on its distribution services?**

A13. Union's distribution rates are established on a cost-of-service basis for a future "test year." As a result, Union's earnings depend on how actual results compare with the assumptions underlying its rates, particularly the assumptions with respect to costs and throughput. In addition, since 1998 Union's earnings have been governed by various performance-based ratemaking (PBR) and earnings sharing mechanisms. As I discuss below, there is continued uncertainty as to the exact form of regulation that will apply to Union in the future.

**Q14. What types of storage services does Union provide and how is income from those services derived?**

A14. Union owns storage facilities with a capacity of approximately 163,500 TJ. Of this, 92,100 TJ is committed to in-franchise customers and 71,400 TJ is available to market to ex-franchise customers.[4] Union's in-franchise storage customers pay cost-based rates and its ex-franchise customers pay market-based rates. Between 75 and 90 percent of the margins from Union's market-based storage sales are returned to its in-franchise customers via reductions in their cost-based rates.[5]

4 Union Prefiled Evidence, Exhibit C3, Tab 4, Schedule 4.

5 "Natural Gas Regulation in Ontario: A Renewed Policy Framework," Report on the Ontario Energy Board Natural Gas Forum, page 41.

Under EBRO 499, the Board provides blanket approval of Union storage contracts that are less than or equal to 2 Bcf and for a term that is less than or equal to 17 months and not covering more than one peak period. Union must submit contracts that are for more than 2 Bcf or for a term greater than 17 months for Board approval.

**Q15. What is the nature of Union's gas transportation business and how does Union earn income on those services?**

A15. Union provides long-term firm "core" and short-term "transactional" transportation services on its Dawn-Trafalgar system. Core transportation services are provided on a cost-of-service basis and are not subject to deferral accounts. These include long-term firm transportation contract services to ex-franchise customers, such as Enbridge, TCPL and GMi. Transactional transportation services have previously been subject to deferral accounts and revenue sharing. Union is proposing to eliminate these deferral accounts and sharing mechanism in 2007 such that all transportation revenues would be subject to variances from the test year forecasts just as its distribution revenues may vary from forecast levels. Union is planning two additional expansions of its Dawn-Trafalgar system in 2006 and 2007 to serve many additional parties under long-term firm contracts.

**Q16. Is Union continuing to make capital investments in these business segments?**

A16. Yes. On the distribution side of the business continued growth in the number of customers (and despite the decline in forecast use per customer) will require Union to invest approximately $477 million in 2006 and 2007.[6] Union is also proposing to invest approximately $250 million for additional transportation service on its Dawn-Trafalgar pipeline over the same time period. As a result, in response to expected growth in the markets it serves, Union continues to put new capital at risk in both the traditional gas distribution business as well as the storage and transportation business.

**Q17. Does the fact that the markets Union serves are expected to grow mean that its assets are likely to be exposed to less business risk?**

[6] Union Prefiled Evidence, Exhibit A2, Tab 1, Schedule 1, pages 34-35 and 38.

A17. No. Risk is not about expectations alone. Risk involves the *uncertainty* associated with the expected outcomes. Some of the riskiest firms that one can evaluate from an investment perspective are those that serve high growth but highly uncertain markets such as telecommunications or technology. A high growth market is certainly a positive factor from an equity investor's perspective *all else equal*. However, that same investor will demand a higher rate of return if the expected growth is more uncertain.

**Q18. What are the principal classes of business risk to which Union is exposed?**

A18. Union is principally exposed to market risk in its gas distribution, storage and transportation businesses. Union is also exposed to regulatory risk, particularly given that there is currently substantial uncertainty over the future regulatory regime that will apply to Union's regulated businesses.

**Q19. How does market risk manifest itself in Union's gas distribution business?**

A19. The market risk to which Union is exposed in its distribution business manifests itself in uncertainty over the future utilization of its distribution assets. Because Union's gas distribution assets are sunk investments, and cannot be redeployed easily to another use should market conditions change, Union's future income earning capability depends critically on the maximum utilization of its assets. While Union has a regulated distribution monopoly in its franchise area, regulation does not provide Union with assured cost recovery protection should its asset utilization differ from its forecasts. In this way, Union bears some market risk that depends on asset utilization.

**Q20. What factors could affect the utilization of Union's distribution assets?**

A20. Distribution asset utilization is a function of the wholesale and retail price of the gas commodity itself, of competing fuels (particularly in the industrial customer class), of general economic activity in its service area, and of weather deviations from normal forecast conditions. Of these risk factors, the ones most important to equity investors (i.e., those that are systematic) are the level of prices and economic activity. Weather deviations from normal, while an important uncertainty for Union, are less important to equity investors because they are not likely to be correlated with the market and hence they are a diversifiable risk. Again, this is because investors themselves can cheaply diversify away risks that are not correlated with movements in the general economy by holding a portfolio of equities, such as broadly-based mutual funds.

**Q21. Is this market risk the same for Union's gas storage and transportation businesses?**

A21. No, it is not. In contrast to its distribution businesses, Union's storage and transportation business faces competition from other suppliers. The effect of competition on the market risk of these businesses is so important that the NEB classifies competitive risk as a separate risk factor when it evaluates the business risk of the gas transmission businesses it regulates.[7]

**Q22. To this point you have not mentioned supply risk. Does Union face supply risk in its gas distribution business?**

A22. Not to a significant degree, in my opinion. This is partly because Union's gas supply costs are a pass-through item in its customers' bills. Of course, to the extent these supply costs rise, the market risk to which Union is exposed increases, as I describe below. But that is not the same as supply risk in that Union does not face a significant risk that the utilization of its facilities will be reduced due to the *unavailability* of supply. Union has access to gas supplies from a wide variety of supply sources and from a major, liquid hub at Dawn, Ontario.

**Q23. How does Union's business risk compare with other gas LDC's, such as those included in Dr. Vilbert's LDC sample?**

A23. Of the eight companies in Dr. Vilbert's U.S. LDC sample, only one has significant lines of business involving the provision of competitive storage and transportation service.[8] Because of the significant component of Union's assets that are employed in the storage and transportation market and exposed to competition, in my opinion Union is somewhat

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7 National Energy Board, Reasons for Decision, RH-2-2004 Phase II, April 2005, pages 26, 43-45.

8 KeySpan Corp. has a 20.4 percent interest in Iroquois Gas Transmission, and a 52 percent and 18 percent interest in the Honeoye and Steuben gas storage facilities, respectively. (See Table MJV-B1 in Appendix B of Dr. Vilbert's evidence for further details on the storage and transportation holdings of the companies in the U.S. LDC sample.)

more risky than the sample of U.S. LDC's that Dr. Vilbert employs for his calculations. I discuss the nature of, and changes in, the risks in Union's storage and transportation business below.

## IV. EVIDENCE OF CHANGES IN UNION'S BUSINESS RISK

**Q24. What changes in the business risk to which Union is exposed since 1998 have you identified?**

A24. I have identified five areas in which there has been a measurable increase in Union's business risk that would matter to investors in its equity securities. These are: 1) Increases in the level and volatility of gas commodity prices, distribution customer elasticity of demand, and thus increased uncertainty in use per customer; 2) Increased potential for bypass of Union's transmission and distribution system; 3) Uncertainty in the growth of gas-fired power generation; 4) Increased competition for Union's storage services and transportation services; and 5) Heightened regulatory uncertainty associated with Union's storage and transportation businesses.

### A. INCREASES IN THE LEVEL AND VOLATILITY OF GAS COMMODITY PRICES, DISTRIBUTION CUSTOMER ELASTICITY OF DEMAND AND UNCERTAINTY IN GAS USE PER CUSTOMER

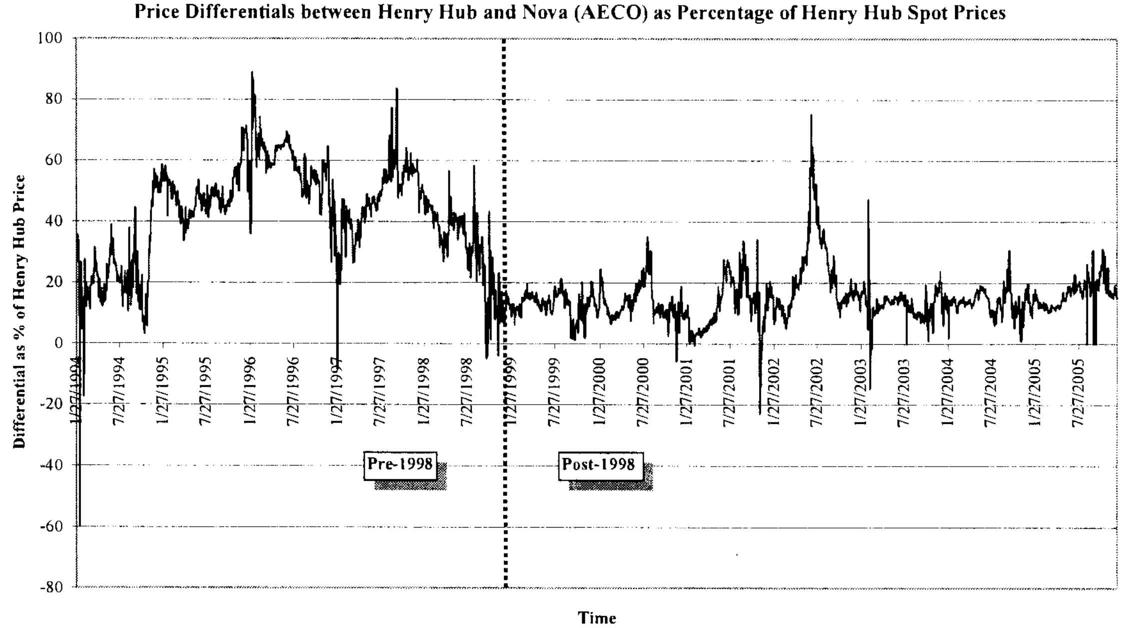
**Q25. Is the current natural gas commodity market in which Union operates different today than it was in 1998?**

A25. Yes. Union is operating in a significantly different gas commodity market today than it was in 1998. In 1998 consumers of Western Canadian gas were coming to the end of a multi-year period in which the price of gas from the Western Canadian Sedimentary Basin ("WCSB") was "disconnected" from (i.e., lower than) the market price of gas from other North American sources. This occurred because growth in WCSB production had outstripped the pipeline capacity available to deliver that gas to the market. Thus, if your gas supplier had access to the WCSB (as Union did), you were enjoying a period in which natural gas was very cheap in absolute and relative terms, with a significant competitive advantage over other energy sources.

That era came to an end with the completion of the TransCanada expansion projects and the construction of the Alliance and Vector systems that went on line in 1999. Instead of too little pipeline capacity out of the WCSB, the market was entering a prolonged period of excess capacity out of the basin. At that point, the price of WCSB gas reconnected with the North American market and it has been connected ever since. This change in the relative prices of WCSB gas and the market price of gas from other sources (as represented by the market price at the Henry Hub) is shown in Figure 1.

**Figure 1**

**Price Differentials between Henry Hub and Nova (AECO) as Percentage of Henry Hub Spot Prices**



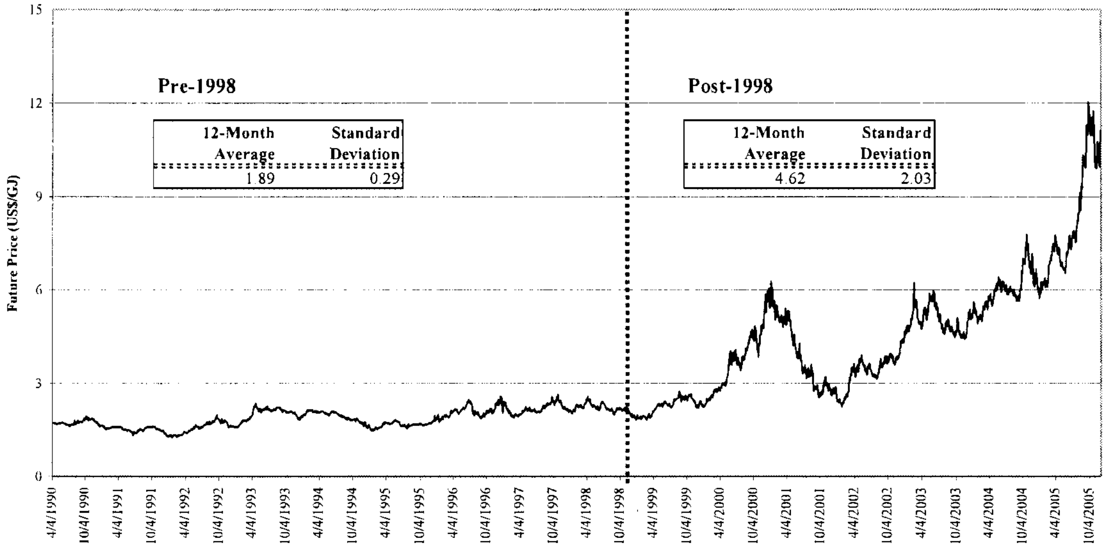

Notes: Null prices are omitted to adjust for inactivity.
Price differentials are calculated as Henry Hub spot prices minus Nova (AECO) spot prices.

**Q26. Is this the only change in the gas commodity market since 1998 worth noting?**

A26. No. If anything the changes just described merely set the stage for the participation of Union, its customers and investors in the even more dramatic increases in the market price and volatility of natural gas experienced since 2000. To show this phenomenon, in Figure 2 I have plotted the 12-month forward "strip" price of natural gas on the New York Mercantile Exchange (NYMEX) from April 1990 to December 2005. This is a useful index to refer to because it reflects the broad market expectation of the level and volatility of future prices in a way that is normalized somewhat for seasonal effects.

**Figure 2**

**Nymex Natural Gas 12-Month Average Future Prices (April 1990 - December 2005)**

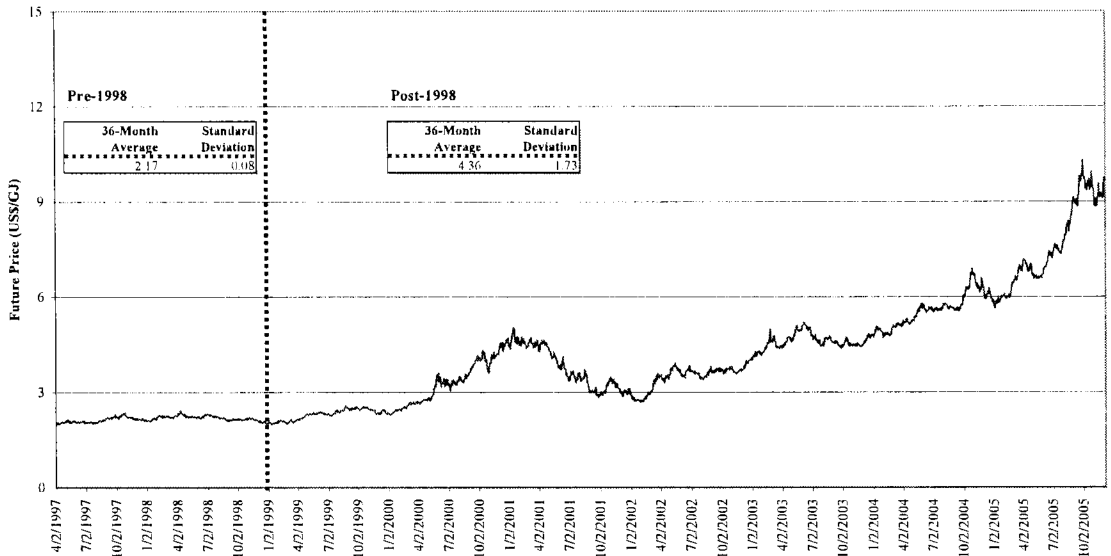



Note: Null prices are omitted to adjust for market inactivity

Prior to 1998 the average of these forward prices was US $1.89 per GJ with a standard deviation of $0.29, a very low and stable environment. (And recall that consumers of WCSB gas enjoyed an even more favourable environment than this during the latter part of this period.) As the figure indicates, since 1998 the average forward price more than doubled to US $4.62 per GJ and the standard deviation of those prices ballooned to $2.03, a seven-fold increase. The same pattern can be seen for 36-month NYMEX forward prices shown in Figure 3.

**Figure 3**

**Nymex Natural Gas 36-Month Average Future Prices**
**(April 1997 - December 2005)**




Note: Null prices are omitted to adjust for market inactivity.

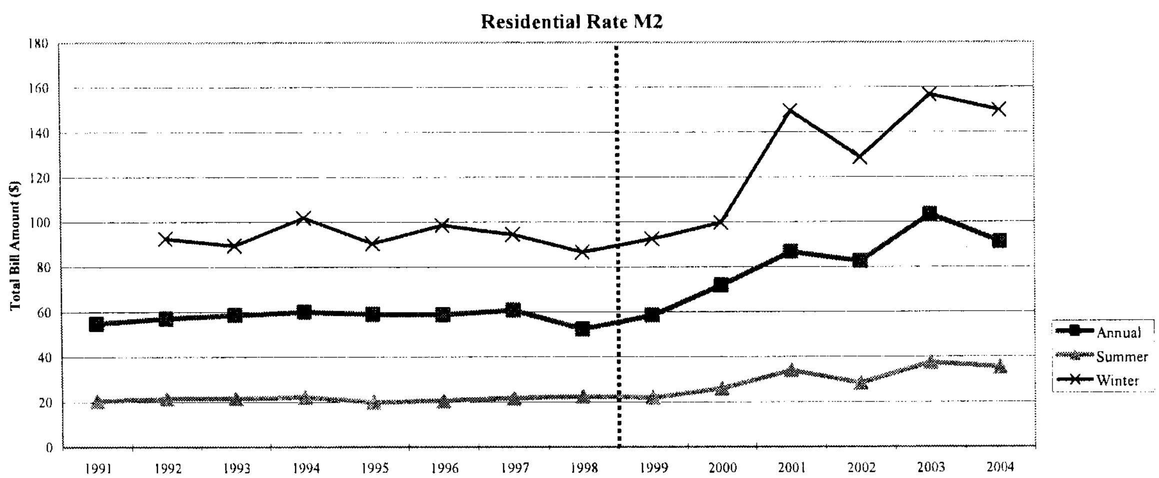
While these changes in the commodity market pre and post-1998 are dramatic, even those averages mask to some extent the market changes experienced in just the last 12 months, as NYMEX forward prices on both a 12 and 36-month basis have risen to the US $9 to $12 per GJ range. This reflects the market's current perception that we have entered a sustained period of high natural gas prices and high price volatility that has not been seen before in North America. Whether or not these changes in the gas commodity market are permanent or temporary is a subject of debate (the market, at least, is forecasting a continuation of the pattern for at least the next three years.) One thing we can be sure of, however, is that there will be continued uncertainty in future prices and increased price volatility.

**Q27. How do these changes in the natural gas commodity price environment translate to Union and its customers?**

A27. Ultimately these price level and volatility changes in the wholesale market are reflected in the retail market. To see this, I have plotted Union's average monthly bill amounts for several of its residential and commercial customer classes by season in Figures 4 through

7. Using Union's residential rate M2 as an example, Figure 4 shows that over the eight years leading up to 1998 the average monthly bill was $57.66 with a standard deviation of $2.80, and that this amount had declined by nearly 4.3% over the period. After 1998 the average residential rate M2 monthly bill was $82.33 (a 43 percent increase) while the standard deviation of those amounts increased to $15.63. As the figure shows, even more dramatic changes are observed in the winter season rates.

**Figure 4**




| Residential M2 | Yearly Average | % Change | Pre-1998 Standard Deviation |
|---|---|---|---|
| Annual | 57.66 | (4.26) | 2.80 |
| Summer | 21.30 | 9.84 | 0.86 |
| Winter | 93.46 | (6.57) | 5.31 |

| Residential M2 | Yearly Average | % Change | Post-1998 Standard Deviation |
|---|---|---|---|
| Annual | 82.33 | 55.97 | 15.63 |
| Summer | 30.53 | 61.38 | 6.09 |
| Winter | 129.50 | 61.89 | 27.59 |

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year.
Rate for Summer 2005 is not available as the latest data provided is March 2005.

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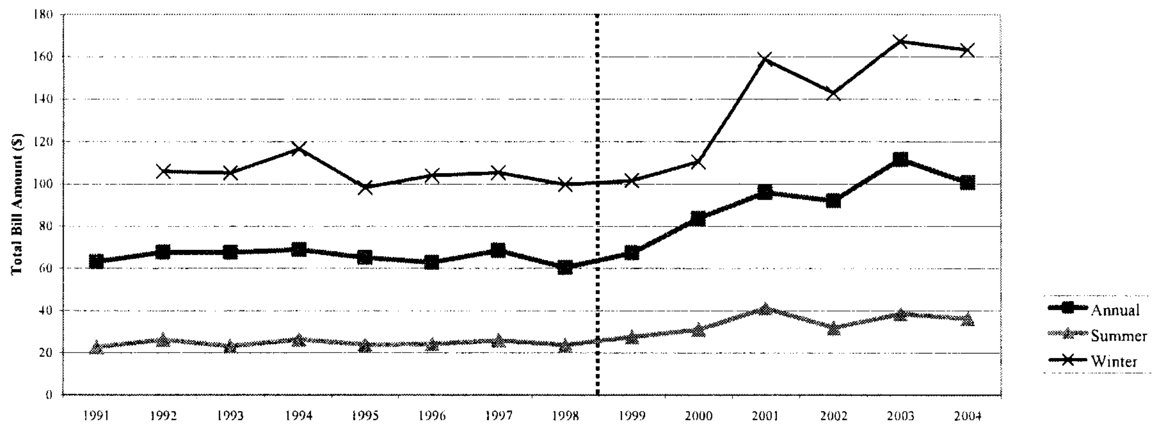
**Figure 5**

**Residential Rate 01**



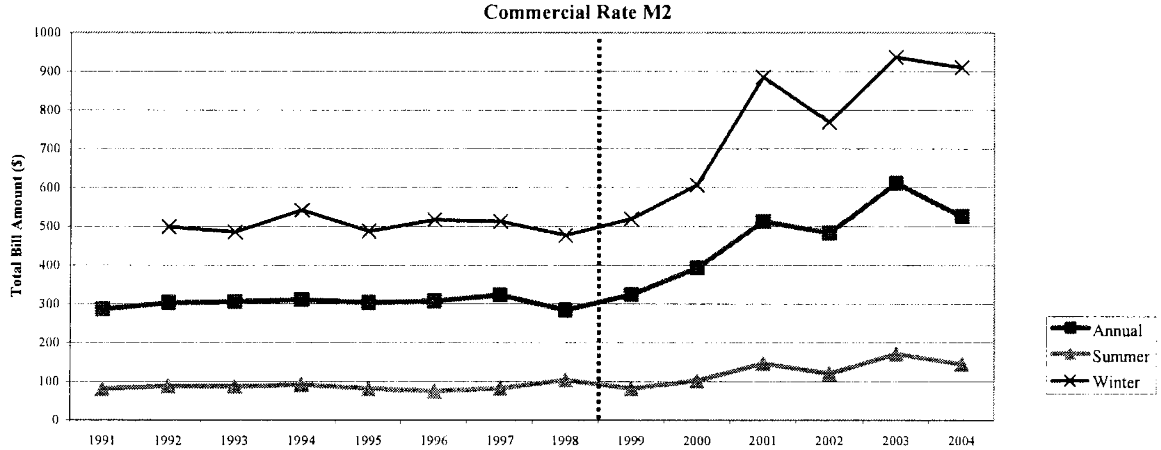

| Residential 01 | | Pre-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 65.56 | (4.29) | 3.15 |
| Summer | 24.52 | 4.95 | 1.45 |
| Winter | 105.06 | (5.81) | 5.92 |

| Residential 01 | | Post-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 91.88 | 49.44 | 15.18 |
| Summer | 34.39 | 31.13 | 5.08 |
| Winter | 140.73 | 60.89 | 28.32 |

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year.
Rate for Summer 2005 is not available as the latest data provided is March 2005.

**Figure 6**

**Commercial Rate M2**



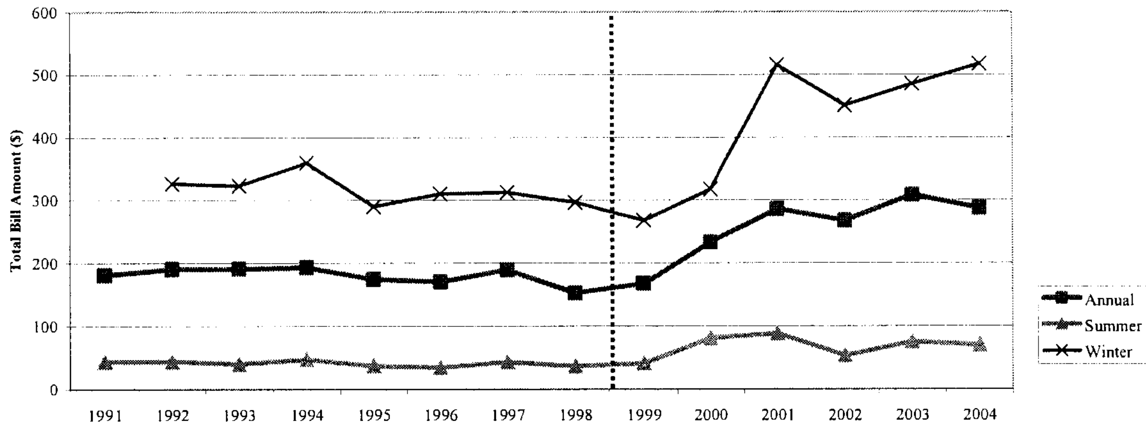

| Commercial M2 | | Pre-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 302.77 | (0.87) | 12.59 |
| Summer | 86.49 | 28.64 | 8.71 |
| Winter | 502.99 | (4.36) | 22.50 |

| Commercial M2 | | Post-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 475.04 | 62.26 | 102.30 |
| Summer | 128.01 | 78.32 | 33.01 |
| Winter | 771.32 | 75.30 | 173.39 |

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year
Rate for Summer 2005 is not available as the latest data provided is March 2005

**Figure 7**

**Commercial Rate 01**




| Commercial 01 | | Pre-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 180.35 | (15.70) | 13.96 |
| Summer | 40.61 | (15.81) | 4.43 |
| Winter | 316.98 | (9.30) | 22.97 |

| Commercial 01 | | Post-1998 | |
|---|---|---|---|
| | Yearly Average | % Change | Standard Deviation |
| Annual | 258.26 | 71.63 | 51.15 |
| Summer | 68.14 | 70.85 | 17.74 |
| Winter | 425.69 | 93.12 | 106.97 |

Notes: Summer rate is calculated using the average of June, July, and August.
Winter rate is calculated using the average of November and December from previous year, January, February, and March from current year.
Rate for Summer 2005 is not available as the latest data provided is March 2005.

These fundamental changes in the commodity price environment have begun to induce changes in customer use of Union's network. This can be seen in decreases in Union's historical and forecast usage per customer and in an increase in customer elasticity of demand.

**Q28. What do the usage per customer statistics show?**

A28. I have asked Union to run its regression models used to estimate usage per customer (Normalized Average Consumption or NAC) using prices for 1998, 2004 and forecast 2007 assuming that no other variables are changing but the price of natural gas reflected in the customers' bills. This exercise will isolate changes in the NAC associated with changes in the gas commodity environment, holding other factors that affect utilization constant. Table 1 shows the results. For example, for residential rate M2 estimated NAC at 1998 price levels is 2,583 $m^3$. At 2004 prices estimated NAC declines to 2,486 $m^3$, or 3.8%. The M2 NAC estimate for 2007 prices based on the current NYMEX forward prices for that time period is 2,397 $m^3$, a decline of an additional 3.6%. Thus, Union's forecasting models suggest that the decline in NAC forecast to occur between 2004 and

2007 is nearly as large as the decline over the entire six years from 1998 to 2004, due to prices alone. Moreover, the forecast *uncertainty* in the residential rate M2 NAC estimate due to prices at a 95 percent confidence limit for 2007 ranges from 2,149 to 2,644 $m^3$, or roughly a 23 percent range from low to high. Therefore, based on historical experience these data tell us that there is a risk that the decline in M2 NAC from 1998 to 2007 could be as high as 17 percent due to the effect of the commodity price alone on residential consumption, with most of the effect occurring after 2004.

## Table 1

**Estimated NAC by Residential Customer Class (Annual $m^3$ per Customer)**

| | Res M2 | Res 01 |
|---|---|---|
| 1998 | 2,583 | 2,568 |
| 2004 | 2,486 | 2,501 |
| 2007 | 2,397 | 2,437 |
| 2007 95% Conf. | 2,149-2,644 | 2,097-2,777 |

Note: Estimated NAC is not reduced for the impact of Union's DSM plan.

Source: Union Gas.

**Q29. How has the elasticity of customer demand changed?**

A29. Another way of describing how the commodity price changes affect Union and its customers is to calculate how the elasticity of demand (represented by percentage change in NAC divided by percentage change in customer bill) has changed over time. Elasticity of demand is a measure of how sensitive customer usage is to changes in price (or their total bill). The higher the elasticity (higher the negative number) is, the more sensitive is usage to price.

These results are summarized in Table 2. For residential rate M2, for example, the elasticity of demand estimated over the period 1998 to 2004 was -0.051. For the period 2004 to 2007 the M2 elasticity estimate nearly doubles to -0.094.

## Table 2

| Change in Estimated NAC Elasticity of Customer Demand | Res M2 | Res 01 |
|---|---|---|
| **NAC Change** | | |
| 2004-1998 | -3.8% | -2.6% |
| 2007-2004 | -3.6% | -2.5% |
| **Bill Change** | | |
| 2004-1998 | 74.0% | 66.5% |
| 2007-2004 | 38.1% | 36.0% |
| **Elasticity** | | |
| 2004-1998 | -0.051 | -0.040 |
| 2007-2004 | -0.094 | -0.071 |

Source: Union Gas.

**Q30. Are these results likely to be conservative?**

A30. Yes they are. These estimates of decline in usage per customer and increase in elasticity of demand were performed using Union's forecasting models. The models, of necessity, estimate these relationships using historical data that do not yet fully incorporate how the very recent changes in prices may influence customer behaviour in the future. For example, if in the residential sector these changes in prices accelerate customers' decisions to conserve natural gas relative to their behaviour in the past, then the use per customer forecasts may be significantly higher than what will actually be experienced. In other words, the estimated elasticities of demand may be conservatively low.

**Q31. How is the change in the commodity price environment affecting the demand for Union's services by industrial customers?**

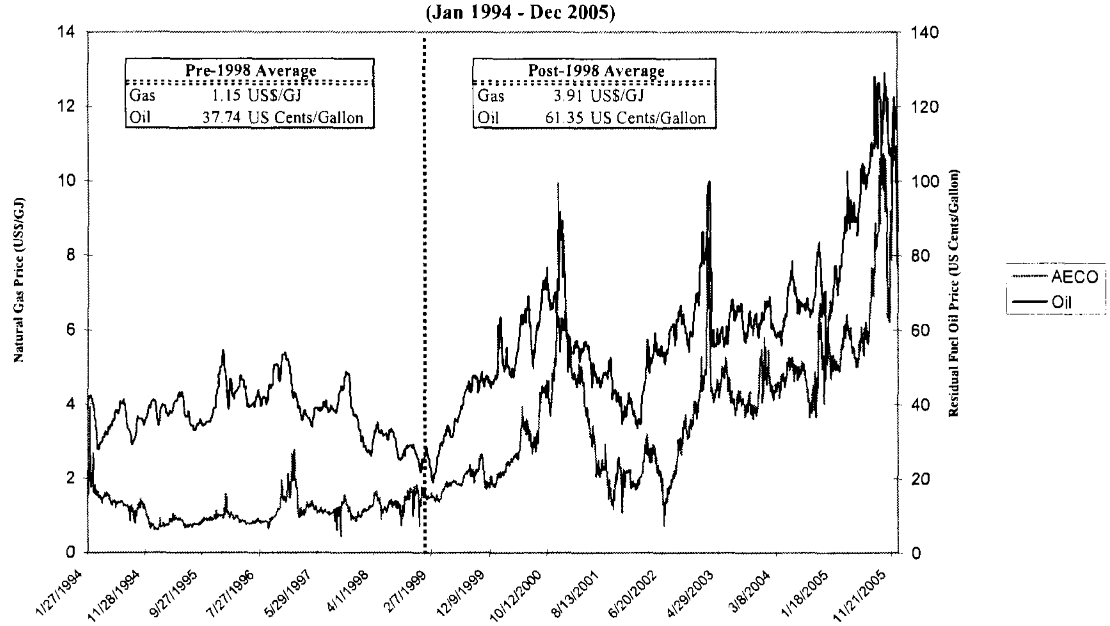
A31. Higher gas commodity prices and higher gas prices relative to the price of alternative fuels, such as heavy #6 fuel oil ("HFO"), have led to demand destruction, plant closures and fuel switching that currently is more than offsetting the growth in the number and production of industrial customers on Union's system.[9] With respect to fuel switching,

[9] Union Prefiled Evidence of Bruce E. Rogers, Exhibit C1, Tab 2, Table 3, page 8.

the change in the relationship between the price of natural gas and the price of HFO since the period prior to 1998 is significant, as seen in Figure 8.

**Figure 8**

**Nova (AECO) Spot Prices and NY Harbor Residual Fuel Oil Spot Prices**
**(Jan 1994 - Dec 2005)**




Note: Null prices are omitted to adjust for inactivity.

Sources: Gas Daily and EIA Petroleum Data.

As the figure indicates, in the period prior to 1998 natural gas at wholesale from the WCSB was quite cheap in comparison to HFO purchased at the New York Harbor. Since 1998, while the average price of HFO has increased by about 63 percent relative to the pre-1998 period, the price of natural gas has increased by 240 percent over the same period. Consequently, the price advantage that natural gas had relative to oil for customers with fuel-switching capability has been essentially eliminated.

**Q32. Can you give an example of how this change in relative prices since 1998 has affected one class of Union industrial customers?**

A32. Yes. Union serves a number of greenhouse customers that have fuel switching capabilities between natural gas and HFO. Using a sample of 59 greenhouse accounts that were in existence in both 1999 and forecast for 2007, Union shows total 1999 consumption for those accounts of 122 $10^6m^3$. Union's current forecast 2007 consumption for those same accounts is 58 $10^6m^3$, a reduction of 53 percent.

**Q33. What do you conclude regarding the effects of the changed gas commodity environment on the risk associated with Union's gas distribution business?**

A33. Equity investors looking at Union's gas distribution business will be primarily concerned with uncertainty surrounding the short and long-term utilization of Union's distribution assets. Since 1998 there has been a fundamental change in the natural gas commodity price environment in which Union operates. This change has already begun to affect negatively the utilization of Union's network across its rate classes, and there is substantial future uncertainty in this utilization. This represents a significant change in Union's business risk.

### B. INCREASED POTENTIAL FOR BYPASS OF UNION'S TRANSMISSION AND DISTRIBUTION SYSTEM

**Q34. Is Union currently at risk for potential bypass of its system?**

A34. Yes, it is. On January 6, 2006 the Board issued a decision regarding the application of Greenfield Energy Centre Limited Partnership ("GEC") to construct a gas pipeline to serve its 1,005 MW gas-fired generating station in Courtright, Ontario, that would bypass Union.[10] Union also filed an application to serve the GEC power station. In its decision the Board authorized both projects, and essentially is "letting the market decide" which project should be built. The policy reflected in this decision increases the uncertainty associated with Union's exposure to future bypass.

**Q35. What is the extent of Union's potential exposure to bypass by its existing customers?**

A35. It is significant. In the evidence filed by Union in the GEC proceeding, it estimated that potential bypass threatens the loss of up to $29 million in annual delivery margin associated with 19 existing customers representing nearly 3,500 $10^6m^3$ of volume.[11] This

[10] Ontario Energy Board, Decision and Order, RP-2005-0022 *et.al.*, January 6, 2006.

[11] Intervenor Evidence of Union Gas Limited, RP2005-0022, page 24 and Schedule 3.

analysis did not consider the potential foregone revenues due to the loss of potential new customers to bypass opportunities.

### C. UNCERTAINTY IN THE GROWTH OF GAS-FIRED POWER GENERATION FORECASTS

**Q36. How has the market to serve gas-fired power generation in Ontario changed since 1998?**

A36. Since 1998 there have been fundamental changes in the structure and regulation of the power generation market in Ontario. Most important to Union's equity investors is the Ontario Government's recent decision to replace coal-fired electricity generation with other technologies on environmental grounds by 2009. The Government has identified new gas-fired power stations as one source that could be relied on. This change in policy has created significant uncertainty as to the extent of new gas-fired power generation demand that may come on line, when, and served by whom. Naturally, this power market uncertainty has a direct effect on uncertainty in the gas market.

**Q37. What is the extent of this uncertainty?**

A37. The extent of the uncertainty can be judged by examining the range of scenarios that the Board Staff identified last November in its *Natural Gas Electricity Interface Review.*[12] In that study Board Staff created three scenarios based on the IESO 10-Year Outlook and various assumptions about technology/fuel choice for power generation. In particular, the high and low scenarios are determined by the demand forecasts and the amount of nuclear generation that is assumed to replace coal technology. The result is gas use growth by gas-fired generators in 2012 that ranges from 164 PJ/year (0.86 PJ/day on peak) in the low scenario to 320 PJ/year (1.35 PJ/day on peak) in the high scenario.[13]

Board Staff has translated this range of uncertainty into scenarios for required investment in natural gas storage and pipeline infrastructure in Ontario by 2012. The extent of this

[12] Ontario Energy Board Staff, *Natural Gas Electricity Interface Review*, EB-2005-0306, November 21, 2005.

[13] *Ibid.*, page 13

uncertainty is huge, from $245 million in the low case to $815 million in the high case. There is also uncertainty as to whether this investment will be required of the utilities or other competitors.

**Q38. If the market is likely to grow, why is this investment risky?**

A38. This investment is risky because there is so much uncertainty in the market, that investors cannot be assured that some of those newly sunk assets will not become stranded or unutilized. While the Board is obviously working hard to assure that there is coordination between the needs of the electricity market and the requirements it places on gas infrastructure, there is risk nonetheless. Board Staff puts it this way in its report:

> A central planning function exists in the electricity market primarily through the IESO and OPA, while no provincial agency exists in the natural gas market. Board staff are not advocating a central planning function in the gas market, but information exchanges could be valuable to stakeholders. This Review is the first step in understanding the implications of new gas-fired power generators for the province's natural gas infrastructure. *However, Board staff realize that there is great uncertainty with respect to future infrastructure requirements, and periodic updates might be required.*[14]

The Staff's report points out that "many stakeholders raised concerns regarding the risks associated with underutilized capacity from overbuilding and/or stranded assets." Board Staff indicated that these issues would be dealt with on a case-by-case basis.[15]

**Q39. What do you conclude about the uncertainty of gas-fired power generation demand for Union's business risk?**

A39. While growth in the demand for gas to supply power generation in Ontario is an opportunity for Union, it is one that creates substantial uncertainty as to the amount, timing, investment requirements, and cost recovery. Moreover, it is an opportunity for Union that faces substantial competition, as reflected in the bypass application of GEC and the Board's regulatory policy to use that competition to pick the winners. As the Board Staff stated in its report cited above, there is no central planning function for gas

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[14] *Ibid.*, pages 27-28, emphasis added.
[15] *Ibid.*, page 25.

infrastructure in Ontario. This set of business risks did not exist at this level of scale or uncertainty in 1998.

### D. INCREASED COMPETITION FOR UNION'S STORAGE SERVICES AND TRANSPORTATION SERVICES

**Q40. How has Union's storage business changed since 1998?**

A40. There has been significant entry by third party storage providers that compete with Union to provide storage services. Several of these storage providers have authorization to charge market-based rates for storage services, and therefore have a great deal of flexibility to design storage services and rates that are attractive to storage customers.

**Q41. Please describe the new storage facilities that compete with Union's storage business.**

A41. Union's gas storage competes with storage facilities located within the Great Lakes region, including storage located in: Ontario, Northern Illinois, Northern Indiana, Michigan and Western New York. Union may also face competition from additional storage providers for some business in a larger geographic region that includes additional storage facilities located in New York, Pennsylvania, Ohio and West Virginia.

Table 3 below lists the new storage capacity added since 1998 in Michigan and New York and West Virginia, and new storage projects planned in these states.

**Table 3**

**Recent Developments in Union's Storage Market**

| Year Online | Location | Additional Inventory Capacity (TJ) | Field | Owner |
|---|---|---|---|---|
| 1999 | Macomb County, Michigan | 44,800 | Washington 10 (Phase I) | DTE |
| 2001 | St. Clair, Michigan | 3,200 | Kimball 27 | WPS Energy Services |
| 2002 | Tioga County, New York | 14,300 | Stagecoach (Phase I) | CNYOG |
| 2004 | Oakland County, Michigan | 1,300 | Lyon 29 | Consumers Energy |
| 2004 | St. Clair, Michigan | 25,800 | Bluewater Gas Storage | Plains All American Pipeline L.P. |
| 2005 | Macomb County, Michigan | 8,800 | Washington 10 (Phase II) | DTE |
| 2006 | Schuyler County, New York | 600 | Seneca Lake | Seneca Lake Storage Inc |
| 2006 | Cattaraugus County, New York Lewis County, West Virginia | 9,900 | Northeast Storage Project | Dominion |
| 2006 | Macomb County, Michigan | 14,800 | Washington 10 (Phase III) | DTE |
| 2006 | Steuben County, New York | 6,300 | Wyckoff | SemGas |
| 2007 | Tioga County, New York | 13,700 | Stagecoach (Phase II) | CNYOG |
| 2007 | Hardy & Hampshire Counties, West Virginia | 12,700 | Hardy Storage | NiSource & Piedmont |
| 2006-2009 | Steuben County, New York | 5,300 | Cohocton Valley | SemGas |

Sources: FERC Major Storage Projects on the Horizon, November 2005; Company Press Releases; Michigan Public Service Commission.

For example, three new third party storage fields were added since 1998 in Michigan: Washington 10 (currently 53,600 TJ, expanding to 68,400 TJ in April 2006) owned by DTE Energy, Bluewater Gas Storage (23,200TJ) owned by Plains All-American Pipeline and the Kimball 27 gas storage field (2,800 TJ) owned by WPS Energy Services. Washington 10 can deliver into Dawn via the Vector or St. Clair pipelines. Bluewater can deliver into Dawn via the Bluewater or Vector pipelines. Kimball 27 can deliver into Dawn via Vector, or via ANR and Michcon. DTE Energy and Plains All-American were granted market-based rates authority for Washington 10 and Bluewater by the Michigan Public Services Commission. WPS Energy was granted market-based rates authority for Kimball 27 by FERC.[16]

**Q42. How does the existence of long term contracts for transportation and storage affect the risk of this part of Union's business?**

A42. The "lumpiness" and sunk cost aspects of pipeline and storage economics means that it is extremely important for suppliers of these services to sell capacity through long-term

[16] "Order Issuing Certificate and Approving Market-Based Rates," FERC Docket No. CP04-80, July 13, 2004.

contracts. Long-term contracts are important because pipeline and storage investments are long-lived and the owners of these assets seek to avoid opportunistic behaviour by shippers (such as by switching carriers in mid-stream if there is capacity available) that would result in stranded capacity or less favourable earnings.

**Q43. What effect does competition among storage and transportation operators have on individual competitors' business risks?**

A43. Competition among storage and transportation providers makes their operations riskier by increasing contractual and throughput uncertainty. A transporter that has competition can lose firm contracts to competing transporters when those contracts expire. The loss of firm contracts or the potential to lose such contracts makes a transporter's revenues and operating cash flows more uncertain than would be the case if it faced limited competition. Increased uncertainty increases risk, and hence, the cost of capital.

One measure of the strength of a transportation and storage provider's competitive position is the remaining duration of its long term contracts with customers. Transportation and storage assets that are underpinned by longer contract durations are less risky to investors. That is one reason why lenders typically require long term contract commitments before they will provide financial commitments to new storage and pipeline projects.

**Q44. How has the duration of Union's storage and transportation contracts changed since 1998?**

A44. Table 4 shows that since 1998 the average remaining duration of Union's existing storage and transportation contracts has declined significantly, from about 8 years in 1998 to 4 years in 2005.

**Table 4**

| Average Outstanding Term of Union's Storage and Transportation Contracts | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | *Forecast* | |
| | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** |
| Number of Customers [1] | 104 | 102 | 101 | 105 | 118 | 130 | 139 | 136 | 133 | 54 | 52 |
| Average Outstanding Contract Term [2] | 9.0 | 8.0 | 8.0 | 8.0 | 4.5 | 3.8 | 3.4 | 3.9 | 4.0 | 5.2 | 5.7 |

Note: [1] 2006 and 2007 includes customers with identified contracts.
[2] 2005-2007 based upon active contracts within the year.

Source: Union Gas;
Union Gas Annual Reports for 1997-2004.

**Q45. What is the implication of this reduction in the outstanding duration of storage and transportation contracts for Union's business risk?**

A45. The implication of this decline in the strength of the contractual underpinnings of Union's storage and transportation service is an increase in business risk.

### E. HEIGHTENED REGULATORY UNCERTAINTY ASSOCIATED WITH UNION'S STORAGE AND TRANSPORTATION BUSINESSES

**Q46. You described changes in Union's market risk due to the increased competition Union's storage and transportation business faces from other suppliers. Are there any indications that this competition may well increase in the future in ways that would be of concern to investors in Union's equity?**

A46. Yes. There is substantial uncertainty associated with the future regulation of Union's storage and transportation business, as recognized by the Board in its Natural Gas Forum process. This uncertainty enhances the competitive risk that Union faces in these markets.

**Q47. What is the nature of this future uncertainty?**

A47. As part of its Natural Gas Forum process, the Board determined that it will begin a proceeding to consider its regulation of storage services in Ontario. Specifically, the Board stated that it "will determine, through a generic hearing, whether it should refrain, in whole or in part, from regulating the rates charged for natural gas storage in

Ontario."[17] The Board envisions a hearing that will encompass a wide variety of issues related to storage and to associated transportation rates and terms of access. The Board listed the following as preliminary issues to be addressed:[18]

- What additional incentives (if any) are needed to ensure adequate storage and transportation development?
- How should storage services be developed for gas-fired power generators?
- Do Union's transportation rates or its operation of its system discriminate against customers, including independent storage operators?
- Are Union's incentives for operating and expanding storage aligned with the public interest?
- Would additional storage development benefit Ontario gas customers by enhancing the liquidity of trading in Ontario?
- If market-based rates are used to expand utilities' storage, should shareholders be asked to bear the associated risk?

The Board stated that the anticipated demand for storage services by natural gas-fired generators raised the following additional questions:[19]

- whether [gas-fired generators] can access storage at COS (cost of service) rates in Ontario for any part of their storage needs;
- the pricing of the more flexible storage services that may be needed; and
- the costs and availability of associated transportation, particularly when the associated transportation would require additional investments.

Finally, the Board stated that several specific issues would need to be addressed in determining whether the Board should refrain from regulating storage rates:[20]

[17] "Natural Gas Regulation in Ontario: A Renewed Policy Framework," Report on the Ontario Energy Board Natural Gas Forum, page 49.
[18] *Ibid.*, page 47, footnote omitted.
[19] *Ibid.*, page 49, footnote omitted.
[20] *Ibid.*, page 50.

- the appropriate product and geographic market for Ontario storage for consumers in different regions of the province
- whether any supplier of storage services has market power in these markets
- the associated transportation issues and the potential impact on competitive storage offerings by utilities and by independent operators
- whether a move to market-based rates for all or some customers is in the public interest, even if the market is competitive
- what, if any, approvals may be required for long-term storage contracts
- the impact of competition on rational development of storage facilities in Ontario.

The Board determined that it will not set cost-of service rates for new storage developed by independent storage providers.

The resolution of all of these issues by the Board will ultimately determine the extent to which the future competitive risk faced by Union in these lines of business will increase over and above what it is currently exposed to.

**Q48. Is this uncertainty as to the future regulatory model affecting Union's storage business today?**

A48. Yes. As discussed above, Union must obtain Board approval for storage contracts greater than 2 Bcf or with a term greater than 17 months. This can be a competitive disadvantage given that Union competes with storage providers that have market-based rates authority and do not have to obtain approval for large or long-term storage contracts.

The Board issued two notices during 2005 inviting comment from interested parties on storage contracts Union submitted to the Board for approval. In the first notice, the Board asked for comment on the following issue: "Is any party adversely affected in any material way by the outcome of the proceeding and if so, what is the impact and how is it material? For example, will a decision to grant the applications adversely affect the

Board's consideration and implementation of the Storage Review?"[21] This approach to the regulation of Union's long-term storage contracts creates additional risk to its business that is currently not faced by its storage competitors.

**Q49. What do you conclude with respect to Union's business risk as it relates to its equity thickness and cost of capital?**

A49. Since the last time the Board examined Union's business risk as it relates to its deemed equity thickness there have been significant changes in the market and competitive landscape in which Union operates. Union's business risk today is higher than it was in 1998 due to fundamental changes and increased uncertainty in gas and oil commodity markets, and in the competition Union faces in its storage and transportation business through new entry and the potential for bypass of its transportation and distribution facilities. Substantial uncertainty as to the effect of the Ontario Government's new gas-fired electricity generation initiatives on required natural gas infrastructure in the province may place potentially new and large financing requirements on Union with uncertain outcomes. Finally, investors in Union's equity will also recognize that there is significant uncertainty as to the regulatory model that will apply to Union in the future, as reflected in the issues before the Board in its Natural Gas Forum process. For all of these reasons I conclude that an increase in Union's equity thickness is warranted.

**Q50. Does this complete your written evidence?**

A50. Yes, it does.

[21] See "Notice of Applications Gas Storage Contract Approvals," RP-2005-0017 *et al.*, July 7, 2005, page 3. See also "Notice of Applications Gas Storage Contract Approvals," RP-2005-0025 *et al.*, October 5, 2005, pages 3-4.

WRITTEN EVIDENCE OF
PAUL R. CARPENTER

## Appendix A: QUALIFICATIONS OF PAUL R. CARPENTER

Dr. Carpenter holds a Ph.D. in applied economics and an M.S. in management from the Massachusetts Institute of Technology, and a B.A. in economics from Stanford University. He specializes in the economics of the natural gas, oil and electric utility industries. Dr. Carpenter was a co-founder of Incentives Research, Inc. in 1983. Prior to that he was employed by the NASA/Caltech Jet Propulsion Laboratory and Putnam, Hayes & Bartlett, and he was a post-doctoral fellow at the MIT Center for Energy Policy Research. He is currently a Principal and Vice Chairman of *The Brattle Group*.

### AREAS OF EXPERTISE

Dr. Carpenter's areas of expertise include the fields of energy economics, regulation, corporate planning, pricing policy, and antitrust. His recent engagements have involved:

- *Natural Gas and Electric Utility Industries*: consulting and testimony on nearly all of the economic and regulatory issues surrounding the transition of the natural gas and electric power industries from strict regulation to greater competition. These issues have included stranded investments and contracts, design and pricing of unbundled and ancillary services, evaluation of supply, demand and price forecasting models, the competitive effects of pipeline expansions and performance-based ratemaking. He has consulted on the regulatory and competitive structures of the gas and electric power industries in the U.S., Canada, the United Kingdom, continental Europe, Australia and New Zealand.

- *Antitrust*: expert testimony in several of the seminal cases involving the alleged denial of access to regulated facilities; analysis of relevant market and market power issues, business justification defenses, and damages.

- *Regulation*: studies and consultation on alternative ratemaking methodologies for oil and gas pipelines, on "bypass" of regulated facilities before the U.S. Congress; advice and testimony before several state utility commissions and the National Energy Board of Canada on new facility certification policy.

- *Finance*: research on business and financial risks in the regulated industries and testimony on risk, cost of capital, and asset valuation for network industries, airports and seaports in the U.S., Canada., Australia and New Zealand.

## PROFESSIONAL AFFILIATIONS

International Association of Energy Economists
American Bar Association (Antitrust Section)
American Economic Association

## ACADEMIC HONORS AND FELLOWSHIPS

Stewart Fellowship, 1983
MIT Fellowships, 1981, 1982, 1983
Brooks Master's Thesis Prize (Runner-up), MIT, 1978

## PUBLICATIONS

"The Advent of U.S. Gas Demand Destruction and Its Likely Consequences for the Pricing of Future European Gas Supplies," (with Carlos Lapuerta and Morten Frisch), 16 March 2005.

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"LNG Access Policy and California," California Resources Agency Workshop on LNG, June 1, 2005

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"CPUC v. El Paso Merchant Energy, et al., FERC Docket No. RP00-241-000," ABA Forum, Washington, DC, September 6, 2001.

"Overseas Experience – Lessons for Australian Gas and Power Markets from California and Europe," 2001 Gas Industry Forum, The Australian Gas Association, Melbourne, Victoria, Australia, June 26, 2001.

"Liberalizing Energy Markets: Lessons from California's Crisis," 20th Annual Conference on US-Turkish Relations, Washington, DC, March 27, 2001.

"Opening Remarks from the Chair: Rates, Regulations and Operational Realities in the Capacity Market of the Future," AIC conference on "Gas Pipeline Capacity '97," Houston, Texas June 17, 1997.

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"The New Effects of Regulation and Natural Gas Field Markets: Spot Markets, Contracting and Reliability," American Economic Association Annual Meeting, New York City, December 29, 1988.

"Appropriate Regulation in the Local Marketplace," Interregional Natural Gas Symposium, Center for Public Policy, University of Houston, November 30, 1988.

"Market Forces, Antitrust, and the Future of Regulation of the Gas Industry," Symposium on the Future of Natural Gas Regulation, American Bar Association, Washington D.C., April 21, 1988.

"Valuation of Standby Tariffs for Natural Gas Pipelines," Workshop on New Methods for Project and Contract Evaluation, MIT Center for Energy Policy Research, Cambridge, March 3, 1988.

"Long-term Structure of the Natural Gas Industry," National Association of Regulatory Utility Commissioners Meeting, Washington D.C., March 1, 1988.

"How the U.S. Gas Market Works"or Doesn't Work," Ontario Ministry of Energy Symposium on *Understanding the United States Natural Gas Market*, Toronto, March 18, 1986.

"The New U.S. Natural Gas Policy: Implications for the Pipeline Industry," Conference on Mergers and Acquisitions in the Gas Pipeline Industry, Executive Enterprises, Houston, February 26-27, 1986.

Various lectures and seminars on U.S. natural gas industry and regulation for graduate energy economics courses at Massachusetts Institute of Technology, 1984-96.

Panelist in University of Colorado Law School workshop on state regulations of natural gas production, June 1985. (Transcript published in *University of Colorado Law Review*.) "Oil Pipeline Rates after the *Williams* 154 Decision," Executive Enterprises, Conference on Oil Pipeline Ratemaking, Houston, June 19-20, 1984.

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"Pricing Solar Energy Using a System of Planning and Assessment Models," Presentations to the XXIV International Conference, The Institute of Management Science, Honolulu, June 20, 1979.

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In the United States District Court for the Western District of Missouri, *Riverside Pipeline Company, L.P., et al., v. Panhandle Eastern Pipeline Company*, September 1998.

In the United States District Court, District of Columbia, *United States of America, Dept. of Justice v. Enova Corporation*, August 1998.

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In the United States District Court for the District of Montana, Butte Division, *Paladin Associates, Inc. v. Montana Power Company*, November- December 1997.

In the United States District Court for the District of Colorado, *Atlantic Richfield Co. v. Darwin H. Smallwood, Sr., et al.*, July 1997.

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In the matter of the Arbitration between *Amerada Hess Corp. v. Pacific Gas & Electric Co.*, May 1995.

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Before the California Public Utilities Commission, Rulemaking on the Commission's Own Motion to Assess and Revise the Regulatory Structure Governing California's Natural Gas Industry, *California Natural Gas Market Conditions Report*, Docket No. R.98-01-011, on behalf of Southern California Edison, July 1998.

Before the National Energy Board of Canada, *Application of Alliance Pipeline Ltd.*, Hearing Order GH-3-97, December 1997, April 1998.

Before the California Public Utilities Commission, *Pacific Enterprises, Enova Corporation, et al. Merger Proceedings,* Docket A.96-10-038, on behalf of Southern California Edison, August 1997.

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Before the U.K. Monopolies and Mergers Commission, *British Gas Transportation and Storage Price Control Review*, on behalf of Enron Capital and Trade Resources Limited, January 1997.

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Before the California Public Utilities Commission, Application of PG&E for Amortization of Interstate Transition Cost Surcharge, Application 94-06-044, on behalf of El Paso Natural Gas, December 1995.

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Before the National Energy Board of Canada, Drawdown of Balance of Deferred Income Taxes Proceeding, RH-1-95, on behalf of Foothills Pipe Lines Ltd., September 1995.

*Pacific Gas Transmission*, FERC Docket No. RP94-149-000, on behalf of El Paso Natural Gas, May 1995.

Before the California Public Utilities Commission, Application of Pacific Pipeline System, Inc., A.91-10-013, on behalf of PPSI, April 1995.

Before the National Energy Board of Canada, *Multipipeline Cost of Capital Proceeding*, RH-2-94, on behalf of Foothills Pipe Lines Ltd., November 1994.

Before the California Public Utilities Commission, Pacific Gas & Electric 1992 Operations Reasonableness Review, Application 93-04-011, on behalf of El Paso Natural Gas, November 1994.

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*Mississippi River Transmission Co.*, FERC Docket No. RP93-4-000, October 1992, September 1993.

*Unocal California Pipeline Co.*, FERC Docket No. IS92-18-000, August 1992.

Before the California Public Utilities Commission, in the Rulemaking into natural gas procurement and system reliability issues, R.88-08-018, June 1992.

Alberta Energy Resources Conservation Board, *Altamont & PGT Pipeline Projects*, Proceeding 911586, March 1992.

Before the California Utilities Commission, on the Application of Southern California Gas Company for approval of capital investment in facilities to permit interconnection with the Kern River/Mojave pipeline, A.90-11-035, May 1992.

*Northern Natural Gas*, FERC Docket No. RP92-1-000, October 1991.

*Florida Gas Transmission*, FERC Docket No. RP91-1-187-000 and CP91-2448-000, July 1991.

*Tarpon Transmission*, FERC Docket No. RP84-82-004, January 1991.

Before the California Public Utilities Commission, on the Application of Pacific Gas & Electric Co. to Expand its Natural Gas Pipeline System, A.89-04-033, May 1990 and October 1991.

*CNG Transmission*, FERC Docket No. RP88-211, March 1990.

*Panhandle Eastern Pipeline*, FERC Docket No. RP88-262, March 1990.

*Mississippi River Transmission*, FERC Docket No. RP89-249, October 1989, September 1990.

*Tennessee Gas Pipeline*, FERC Docket No. CP89-470, June 1989.

*Empire State Pipeline*, Case No. 88-T-132 before the New York Public Service Commission, May 1989.

Before the U.S. Congress, House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power, Hearings on "Bypass" Legislation, May 1988.

*Tennessee Gas Pipeline*, FERC Docket No. RP86-119, 1986-87.

*Mojave Pipeline Co.*, FERC Docket No. CP85-437, 1987-88.

*Consolidated Gas Transmission Corp.*, FERC Docket No. RP88-10, 1988.

*Panhandle Eastern*, FERC Docket No. RP85-194, 1985.
On behalf of the Natural Gas Supply Association in FERC Rulemaking Docket No. RM85-1, 1985-86.

On behalf of the Panhandle Eastern Pipeline Co. in FERC Rulemaking Docket No. RM85-1, 1985.

EB-2005-0520
Exhibit E2
Tab 3

**WRITTEN EVIDENCE**

**OF**

**MICHAEL J. VILBERT**

**FOR**

**UNION GAS LIMITED**

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

January 2006

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WRITTEN EVIDENCE OF
MICHAEL J. VILBERT

# I. INTRODUCTION AND SUMMARY

**Q1. Please state your name and address for the record.**

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

**Q2. Please summarize your background and experience.**

A2. I am a Principal of The Brattle Group, ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, Brussels and San Francisco.

My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania. Appendix A to this written evidence is a more complete description of my professional qualifications.

**Q3. What is the purpose of your written evidence in this proceeding?**

A3. For 2005, the Ontario Energy Board's ("OEB" or the "Board") benchmark rate of return on equity for Union Gas Limited ("Union" or the "Company") of 9.63 percent. Union has asked Brattle (my colleagues, Dr. A. Lawrence Kolbe, Dr. Paul R. Carpenter and me) to estimate the deemed equity component for the Company that would be consistent with a 9.63 percent return on equity, the market-derived cost of capital information from the sample companies and the risk of Union Gas. We have also been asked to estimate the deemed equity component consistent with an 8.89 percent return on equity that would be the 2006 rate of return using the OEB's formula. My role is to estimate the overall cost of capital for the sample companies and the deemed equity ratio consistent with the sample information.

**Q4. Please summarize any parts of your background and experience that are particularly relevant to your written evidence on these matters.**

A4. Brattle's specialties include financial economics, regulatory economics, and the gas and electric industries.

I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. I have testified on the cost of capital before the Alberta Energy and Utilities Board ("AEUB") on behalf of TransAlta Utilities in 1999 and on behalf of NOVA Gas Pipeline Limited in 2003, before the National Energy Board ("NEB") on behalf of TransCanada Pipelines Limited for the Mainline in 2002 and 2004, and before the Newfoundland & Labrador Board of Commissioners of Public Utilities on behalf of Industrial Customers of Newfoundland and Labrador Hydro in 2001. I have filed written evidence before the AEUB in 2000, and I have testified before the U.S. Federal Energy Regulatory Commission ("FERC") and before state regulatory commissions. Appendix A is a more detailed summary of my qualifications.

**Q5. Please summarize your analysis of the benchmark samples' deemed equity component, starting with an overview of how you approached the task.**

A5. The traditional approach to estimating the required return for a regulated utility focuses on the individual components of a company's overall cost of capital. In particular, decisions regarding the "right" cost of equity and capital structure may be made separately, without specific consideration of the impact of one decision on the other component.[1] As Dr. Kolbe explains in his written evidence, this could lead to a mistake in the relationship between the allowed return on equity and the regulatory capital structure. I avoid this problem by estimating the sample companies' overall after-tax weighted-average cost of capital ("ATWACC"). Note that the weights in the ATWACC calculation are the market values of debt, preferred equity and common equity in the sample company's capital structure not the book value amounts. Market value is the value of a company's securities (debt and equity) as traded in capital markets. The calculation of the market values of the individual components is discussed below in Section IV-A.2.

[1] Dr. Kolbe and I use "cost of equity" in the finance textbook sense, to refer to the expected rate of return in capital markets that is available on alternative investments of equivalent risk to the equity in question.

Using the sample average ATWACC, I then calculated the deemed equity component that is consistent with a particular return on equity. This procedure avoids the potential inconsistency between the allowed return on equity and the regulatory capital structure.

**Q6. Please outline the steps in your analysis.**

A6. To evaluate the deemed equity component for the Company, I analyze two samples: a sample of Canadian regulated utilities and a sample of U.S. gas local distribution companies ("LDCs"). I first estimate the cost of equity for the companies in the two benchmark samples using the risk positioning approach and the discounted cash flow method. Using the cost of equity estimates for each company and the company's market costs of debt and preferred stock, I calculate each firm's ATWACC using the company's market-value capital structure. The result is a sample average ATWACC for each cost of equity estimation method. In accordance with the Company's request, I then report the deemed equity ratio consistent with each sample's average estimated ATWACC as if the market-determined rate of return on equity had been 9.63 percent or 8.89 percent. I thus present the deemed equity component that is consistent with the OEB's formula-determined rate of return on equity for Union and the market-determined information on the sample's overall average cost of capital.

**Q7. Are the sample estimates of the deemed equity ratio the end of the analysis?**

A7. No. The overall cost of capital and deemed equity estimates of the two samples are evaluated by Dr. Kolbe, who first, reviews the evidence of Dr. Carpenter on the relative risk of Union in relation to the benchmark samples and the changes in the risk of Union since 1998, and then determines the Company's deemed equity ratio corresponding to the 9.63 percent and 8.89 percent rates of return on equity derived from the Board's cost of equity formula.

**Q8. Please summarize your findings about the benchmark samples' costs of capital.**

A8. I report results for the full group of companies in the Canadian utility and the U.S. gas LDC samples as well as for two subsamples characterized by having fewer data problems or having a larger fraction of revenues from regulated operations. For both samples, the results of the DCF model are more variable and are less reliable than those based upon the risk positioning model; however, I provide results using the DCF method because it is a method that has been used extensively in the past. In addition, the DCF model results serve as a check on the results from the equity risk positioning approach, but I rely primarily on the risk positioning model.

Consistent with a rate of return on equity of 9.63 percent, the most reliable of the risk positioning approaches on the more reliable subsamples yields a point estimate of the deemed equity ratio of 44 percent for the Canadian utility sample and 46 percent for the

U.S. gas LDC sample. However, it is more correct to say that the risk positioning estimates imply a range of deemed equity components consistent with the sample evidence of 40 to 48 percent equity for the Canadian sample and 42 to 50 percent equity for the gas LDC sample when the rate of return on equity is 9.63 percent. If the market determined cost of equity were 8.89 percent, the point estimate of the deemed equity ratio increases to about 50 percent for the Canadian sample with a range of 46 to 54 percent and 52 percent with a range of 48 to 56 percent for the gas LDC sample.

I specify the capital structure range to the nearest 4 percent which corresponds roughly to the nearest ¼ percent in the estimated ATWACC. Using the most reliable of the risk positioning methods the ATWACC is about 6 percent for the Canadian utility sample and slightly over 6 percent for the U.S. gas LDC sample with a range of 5¾ to 6¼ percent. All calculations supporting my analyses are presented in the attached tables labeled Table No. MJV-1 to Table No. MJV-22.

**Q9. How is your written evidence organized?**

A9. *Section II* formally defines the cost of capital and touches on the principles relating to the cost of capital and capital structure for a business. Dr. Kolbe's written evidence provides additional detail on these points. *Section III* presents the methods used to estimate the cost of capital for the benchmark samples. *Section IV* provides the associated numerical analyses, and explains the basis of my conclusions for the benchmark samples' overall costs of capital and deemed equity component consistent with the 9.63 and 8.89 percent rates of return on equity. Appendices B and C support *Section III* and *Section IV* with additional details on the risk positioning and DCF approaches, respectively, including the details of the numerical analyses.

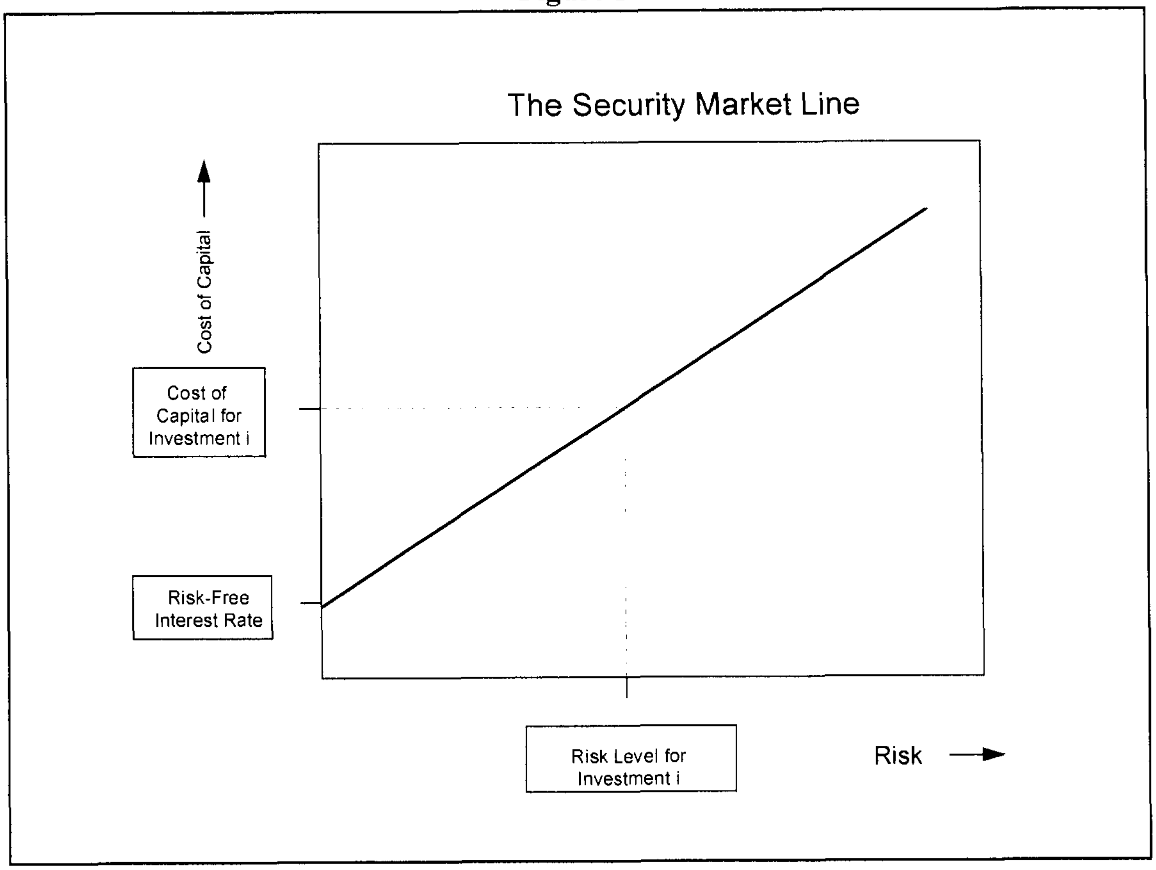
## II. DETERMINANTS OF THE COST OF CAPITAL

### A. THE COST OF CAPITAL AND RISK

**Q10. Please formally define the "cost of capital."**

A10. The *cost of capital* can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk.* In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect"and "expected" in this written evidence, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

**Figure 1**




The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 1. The higher the risk, the higher the cost of capital. A version of Figure 1 applies for all investments. However, for different types of securities, the location of the line may depend on corporate and personal tax rates.

**Q11. Why is the cost of capital relevant in rate regulation?**

A11. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investment.[2] That practice normally is viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 678 (1923), and *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944). In Canada the comparable decision is *Northwestern Utilities v. City of Edmonton (1929) S.C.R. 186.*

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulators normally try to prevent such outcomes, unless there are offsetting benefits to customers (e.g., from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital shortchanges investors. In the long run, such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that on other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the economic issues an inadequate return raises for them. In the short run, deviations of the expected rate of return on the

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[2] To the best of my knowledge, the first paper formally to link the cost of capital as defined by financial economics with the correct expected rate of return for utilities is Stewart C. Myers, *Application of Finance Theory to Public Utility Rate Cases,The Bell Journal of Economics and Management Science*, 3:58-97 (Spring 1972).

rate base from the cost of capital create a "zero-sum game"-- investors gain if customers are overcharged, and customers gain if investors are shortchanged. In the long run, however, inadequate returns are likely to cost customers -- and society generally -- far more than is gained in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than the gains from short-run shortfalls from the cost of capital. Moreover, in capital-intensive industries (such as gas distribution, storage and transmission), systems that take a long time to decay cannot be fixed overnight, either. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that it does not fall short of the cost of capital, either.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital even if the allowed rate of return equals the cost of capital exactly. However, a regulator that on average sets rates so investors expect to earn the cost of capital treats both customers and investors fairly, and acts in the long-run interests of both groups.

## B. THE RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND THE COST OF EQUITY

**Q12. Please explain why it is necessary to report the deemed equity component adjusted for the cost of equity.**

A12. Dr. Kolbe's written evidence covers this topic in detail. Briefly, the cost of equity and the capital structure are inextricably intertwined in that the use of debt increases the financial risk of the company and therefore increases the cost of equity. The more debt, the higher the cost of equity for a given level of business risk. Rate regulation normally focuses on the components of the overall cost of capital, and in particular, on what the "right" cost of equity and capital structure should be. The overall cost of capital depends primarily on the business the firm is in, while the costs of the debt and equity components depend not only on the business risk but also on the distribution of revenues between debt and equity. The overall cost of capital is thus the more basic concept. Although the overall cost of capital is constant (ignoring taxes and costs of excessive debt), the distribution of the costs among debt and equity is not. Section III and Appendix B of Dr. Kolbe's evidence set out the principles and procedures on which I rely.

## C. IMPLICATIONS FOR ANALYSIS

**Q13. Please explain how you determine the deemed equity ratio that is consistent with the market evidence on the sample companies' overall cost of capital.**

A13. Traditional approaches often involve estimating the cost of equity for each of the sample firms without explicit consideration of the market-value capital structure underlying those costs. Then, relying on the sample's average cost of equity, one estimates the cost of equity for the company in question. Note that the traditional method often makes no direct connection between differences in the capital structure of the sample firms used to estimate the cost of equity and the regulatory capital structure used to set rates. Consequently, the allowed return on equity does not necessarily correspond to the financial risk faced by shareholders and could lead to an unfair rate of return.

I avoid this problem by calculating each sample company's overall after-tax weighted-average cost of capital using its market value capital structure. Using the sample average overall cost of capital, I then determine the corresponding deemed equity component at a 9.63 percent or a 8.89 percent rate of return on equity that maintains the sample average ATWACC. In other words, if I know the cost of debt and equity, I can calculate the amount of equity and debt in the capital structure that results in an ATWACC value equal to the sample's average ATWACC. This procedure ensures that the capital structure and the allowed cost of equity are consistent with information from the capital markets on the overall cost of capital.

**Q14. Can you provide a simple example of the calculation of the deemed equity ratio consistent the market-determined estimate of the sample's average overall cost of capital?**

A14. Yes. Consider the following equation:[3]

$$ATWACC = r_D \times (1 - T_C) \times (1 - E) + r_E \times E \quad \textbf{(1)}$$

where $r_D$ = market cost of debt,
$r_E$ = market cost of equity,
$T_C$ = corporate income tax rate,
$(1-E)$ = percent debt in the market value capital structure, and
$E$ = percent equity in market value capital structure.

The amount of equity in the capital structure consistent with overall cost of capital estimate (ATWACC), the market cost of debt and equity and the corporate income tax rate can be determined by solving equation (1) for E.

[3] Note that this equation assumes that only debt and equity are in the market value capital structure, but it is simple to add preferred equity to the equation.

## III. COST OF EQUITY ESTIMATION METHODS

**Q15. Please summarize the principles of your cost of equity estimation methods.**

A15. Recall the definition of the cost of capital from the outset of my written evidence: the expected rate of return in capital markets on alternative investments of equivalent risk. My cost of capital estimation procedures address three key points implied by the definition:

1. Since the cost of capital is an *expected* rate of return, it cannot be directly observed; it must be inferred from available evidence.
2. Since the cost of capital is determined *in capital markets* (*e.g.*, the Toronto Stock Exchange), data from capital markets provide the best evidence from which to infer it.
3. Since the cost of capital depends on the return offered by alternative investments *of equivalent risk*, measures of the risks that matter in capital markets are part of the evidence that needs to be examined.

**Q16. How does the above definition help in cost of capital estimation?**

A16. The definition of the cost of capital recognizes a tradeoff between risk and expected return, plotted above in Figure 1, the security market line. Cost of capital estimation methods take one of two approaches: (1) they try to identify a comparable-risk sample of companies and to estimate the cost of capital directly; or (2) they establish the location of the security market line and estimate the relative risk of the security, which jointly determine the cost of capital. In terms of Figure 1, the first approach focuses directly on the vertical axis, while the second focuses both on the security's position on the horizontal axis and on the position of the security market line.

The first type of approach is more direct, but ignores the wealth of information available on securities not thought to be of precisely comparable risk. The "discounted cash flow" or "DCF" model is an example. The second type of approach, the risk positioning approach (sometimes known as "equity risk premium approach"), requires an extra step, but as a result can make use of information on all securities, not just a very limited subset. The Capital Asset Pricing Model ("CAPM") is an example. While both approaches can work equally well if conditions are right, one may be preferable to the other under certain circumstances. In particular, approaches that rely on the entire security market line are less sensitive to deviations from the assumptions that underlie the model, all else equal. I examine both DCF and risk positioning approach evidence for the samples.

## A. THE EQUITY RISK PREMIUM MODEL

**Q17. How does the equity risk premium model work?**

A17. The equity risk premium approach estimates the cost of equity as the sum of a current interest rate and a risk premium. This approach may sometimes be applied informally. For example, an analyst or a regulator may check the spread between interest rates and what is believed to be a reasonable estimate of the cost of capital at one time, and then apply that spread to changed interest rates to get a new estimate of the cost of capital at another time.

More formal applications of equity risk premium method implement the second approach to cost of capital estimation. They use information on all securities to identify the security market line (Figure 1) and derive the cost of capital for the individual security based on that security's relative risk. This equity risk premium approach is widely used and underlies most of the current scholarly research on the nature, determinants and magnitude of the cost of capital.

**Q18. How are "more formal applications" put into practice?**

A18. The essential benchmarks that determine the security market line are the risk-free interest rate and the premium that a security of average risk commands over the risk-free rate. This premium is commonly referred to as the "market risk premium" ("MRP"), *i.e.*, the excess of the expected return on the average common stock over the risk-free interest rate. In the equity risk premium approach the risk-free interest rate and MRP are common to all securities. A security-specific measure of relative risk (beta) is estimated separately and combined with the MRP to obtain the company-specific risk premium.

In principle, there may be more than one benchmark risk premium, each with its own security-specific measure of relative risk. For example, the "arbitrage pricing theory" and other "multi-factor" models have been proposed in the academic literature. These models estimate the cost of capital as the sum of a risk-free rate and several security-specific risk premiums. However, none of these alternative models has emerged in practice as "the" improvement to use instead of the original, single-factor model.

I use the traditional single-factor model in this written evidence. Accordingly, the required elements in my formal equity risk premium approach are the market risk premium, an objective measure of relative risk (beta), the risk-free rate that corresponds to the measure of the market risk premium, and a specific method to combine these elements into an estimate of the cost of capital.

**Q19. How do you combine the above components into an estimate of the cost of capital?**

A19. By far the most widely used approach to estimation of the cost of capital is the Capital Asset Pricing Model, and I do calculate CAPM estimates. However, the CAPM is only one equity risk premium approach technique. I also use another risk positioning model, namely the Empirical Capital Asset Pricing Model ("ECAPM").

#### 1. The Capital Asset Pricing Model

**Q20. Please start with the CAPM, by describing the model.**

A20. As noted above, the modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a risk premium. The CAPM is the longest-standing and most widely used of these theories. The CAPM states that the cost of capital for an investment, *I*, (*e.g.*, a particular common stock) is given by the following equation:

$$k_i = r_F + \beta_i \times \text{MRP} \qquad \textbf{(2)}$$

where $k_i$ is the cost of capital for investment *I*; $r_F$ is the risk-free rate, $\beta_i$ is the beta risk measure for the investment *I*; and MRP is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities do. It says that the security market line starts at the risk-free interest rate (that is, that the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). It further says that the risk premium over the risk-free rate equals the product of beta and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

### 2. The Empirical Capital Asset Pricing Model

**Q21. What other equity risk premium approach model do you use?**

A21. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premia than predicted by the CAPM and high-beta stocks tend to have lower risk premia than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but this finding can also be used to estimate the cost of capital directly, using beta to measure relative risk without simultaneously relying on the CAPM.

The second model makes use of these empirical findings. It estimates the cost of capital with the equation,

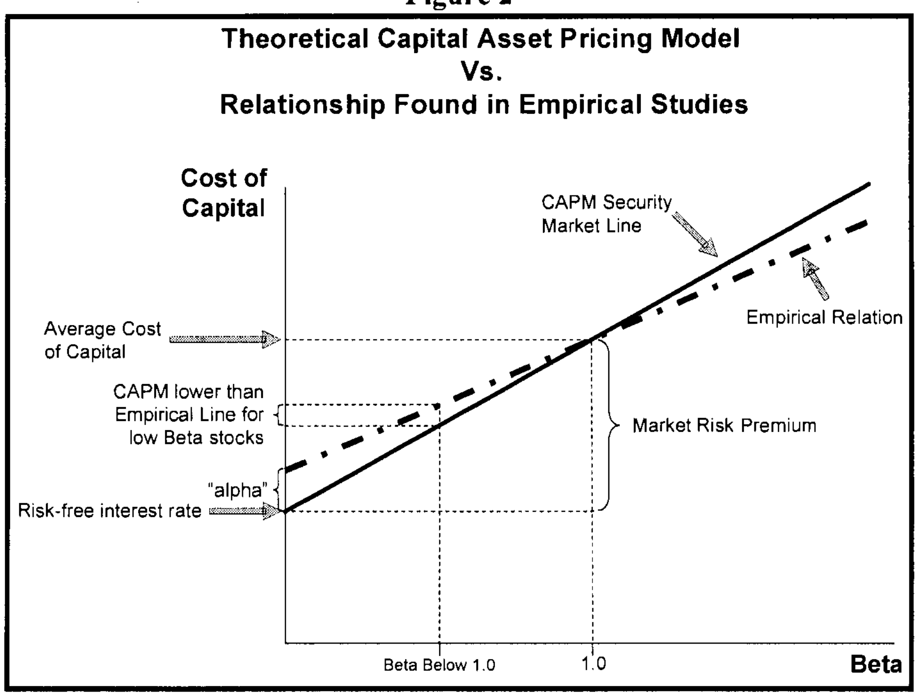
$$k_i = r_F + \alpha + \beta_i \times (\text{MRP} - \alpha) \tag{3}$$

where $\alpha$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as above. I label this model the Empirical Capital Asset Pricing Model, or "ECAPM."

**Q22. Why is it appropriate for you to use the empirical CAPM?**

A22. To the best of my knowledge the CAPM has failed every empirical test. The ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is a recognition that the actual slope of the risk-return tradeoff is flatter than predicted and the intercept higher based upon repeated empirical tests of the CAPM. The alpha parameter ($\alpha$) in the ECAPM adjusts for this fact. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 2.

**Figure 2**



For the long-term risk-free rate models, I set alpha equal to both one percent and two percent, but I rely more heavily on the one percent results. The use of a long-term risk-free rate incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the Security Market Line has a higher intercept and a flatter slope than the short-term risk-free version which has been extensively tested. Thus, it is likely that I do not need to make the same degree of adjustment when I use the long-term risk-free rate, and these $\alpha$ values are lower than would be justified by the magnitude of the misestimation in the tests of the CAPM. Please see Table No. MJV-B2 in Appendix B for a summary of the empirical evidence on the size of the required adjustment.

## B. SECURITY MARKET LINE BENCHMARKS

**Q23. What does this section of your evidence cover?**

A23. This section covers the benchmark parameters necessary to estimate the security market line displayed in Figure 1.

**Q24. What benchmarks parameters are used to determine the location of the security market line?**

A24. The essential benchmarks that determine the security market line are the risk-free interest rate and the premium that a security of average risk commands over the risk-free rate. This premium is commonly referred to as the "market risk premium" ("MRP"), *i.e.*, the excess of the expected return on the average common stock over the risk-free interest rate. In the risk positioning approach, the risk-free interest rate and MRP are common to all securities. A security-specific measure of relative risk (beta) is estimated separately and combined with the MRP to obtain the company-specific risk premium.

### 1. Market Risk Premium

**Q25. Why is a risk premium necessary?**

A25. Experience (*e.g.*, the U.S. market's October Crash of 1987) demonstrates that shareholders, even well diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free Government Treasury bills, investors subject themselves not only to the risk of earning a return well below those they expected in any year but also to the risk that they might lose much of their initial capital. This is why investors demand a risk premium.

In regulatory proceedings, two versions of the Capital Asset Pricing Model ("CAPM") are often reported. The first version measures the market risk premium as the risk premium of average risk common stocks over short-term Treasury bills, which is the usual measure of the "market risk premium" used in capital market theories. The second version measures the risk premium relative to a long-term risk-free rate. To determine the cost of capital in a regulatory proceeding, the MRP should be used with a *forecast* of the same interest rate used to calculate the MRP (*i.e.*, the short-term Treasury bill rate or the long-term Government rate). In this proceeding, I report results only for the version of the CAPM that relies upon the long-term risk-free rate.

**Q26. How do you estimate the MRP?**

A26. There is presently little consensus on "best practice" for estimating the MRP (which is not the same thing as saying that all practices are equally good). For example, the latest edition of the leading graduate textbook in corporate finance, after recommending use of the arithmetic average realized excess return on the market for many years (which for a while was noticeably over 9 percent in the U.S.), reviews the current state of the research and expresses the view that the a range between 5 to 8.0 percent (short-term MRP) is reasonable for the U.S.[4,5]

The best selling text in corporate finance in Canada calculates the average arithmetic market risk premium in Canada to be 6.53 percent over the period 1948-2003

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4 Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance,* McGraw-Hill, 8th edition, 2006, pp. 151-154.

5 In past editions, the authors expressed the view that they are "most comfortable" with values toward the upper end of that range, but this language does not appear in the 8th edition. Although Professor Myers still holds this view, this language and other sections were dropped to accommodate a request to reduce the length of the text.

but only 3.84 percent for the period 1957 to 2003.[6] The authors conclude by suggesting that a (short-term) MRP "of around 4 percent is a quite reasonable prediction for the equity MRP in Canada looking to the future. However, we do have to acknowledge that this remains a controversial issue about which experts disagree."[7]

My written evidence considers both the historical evidence and the results of scholarly studies of the factors that affect the risk premium for average-risk stocks in order to estimate the benchmark risk premium investors currently expect. I consider the historical differences between the S&P/TSX Composite Index[8] ("S&P/TSX") and the risk-free rate for the Canadian market risk premium, historical differences between the Standard and Poor's 500 ("S&P 500") and the risk-free rate for the U.S. market risk premium, and the relationship between the market returns in Canada and in the U.S. Finally, I reviewed Ibbotson Associates discussion on the "International Cost of Capital" in the *SBBI: Valuation Edition 2005 Yearbook*.[9] The international cost of equity models reviewed in Ibbotson result in estimates of the Canadian MRP that are greater than the MRP in the U.S. rather than less as is the result based upon historical realized returns.

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6 Stephen A. Ross, Randolph W. Westerfield, Jeffrey F. Jaffe, and Gordon S. Roberts, *Corporate Finance*, 4th Canadian ed, McGraw-Hill Ryerson (2005), pp.268- 283.

7 *Ibid.*, p. 282.

8 Prior to May 1, 2002 the key index on the Toronto Stock Exchange was the TSE 300 composite index ("TSE 300") which was always composed of 300 companies. The index was replaced by the S&P/TSX composite index on May 1, 2002. The number of companies in the latter index is not fixed but consists of those companies that meet Standard & Poor's inclusion criteria.

9 See *SBBI: Valuation Edition 2005 Yearbook*, pp. 171-180.

**Q27. Please summarize the recent literature on the MRP and the conclusions you draw from it?**

A27. The new research based upon U.S. data challenges the conventional wisdom of using arithmetic average historical excess returns to estimate the MRP. However, after reviewing the issues in the debate, I remain skeptical for several reasons that the market risk premium has declined substantially in the U.S. or in Canada.

First, despite eye-catching claims like "equity risk premium as low as three percent,"[10] and "the death of the risk premium,"[11] not all recent research arrives at the same conclusion. In his presidential address to the American Finance Association in 2001, Professor Constantinides seeks to estimate the unconditional equity premium based on average historical stock returns.[12] (Note that this address was based upon evidence just before the major fall in market value.) He adjusts the average returns downward by the change in price-earnings ratio because he assumes no change in valuations in an unconditional state. His estimates for 1926 to 2000 and 1951 to 2000 are 8.0 percent and 6.0 percent, respectively, over the 3-month T-bill rate. In another published study in 2001, Professors Harris and Marston use the DCF method to estimate the market risk

10 Claus, J. and J. Thomas, (2001), "Equity Risk Premium as Low as Three Percent: Evidence from Analysts' Earnings Forecasts for Domestic and International Stocks," *Journal of Finance* 56:1629-1666.

11 Arnott, R. and R. Ryan, (2001), "The Death of the Risk Premium," *Journal of Portfolio Management* 27(3):61-84.

12 Constantinides, G.M. (2002), "Rational Asset Prices," *Journal of Finance* 57:1567-1591.

premium for the U.S. stocks.[13] Using analysts' forecasts to proxy for investors' expectation, they conclude that over the period 1982-1998 the MRP over the **long-term risk-free rate** is 7.14 percent. As yet another example, the paper by Drs. Ibbotson and Chen (2003) adopts a supply side approach to estimate the forward looking long-term sustainable equity returns and equity risk premium based upon economic fundamentals. Their equity risk premium **over the long-term risk-free rate** is estimated to be 3.97% in geometric terms and 5.90% on an arithmetic basis. They conclude their paper by stating that their estimate of the equity risk premium is "far closer to the historical premium than being zero or negative."[14]

Second, Professor Ivo Welch surveyed a large group of financial economists in 1998 and 1999. The average of the estimated MRP was 7.1 percent in Prof. Welch's first survey[15] and 6.7 percent in his second survey which was based on a smaller number of individuals. However, a more recent survey by Prof. Welch reported only a 5.5 percent MRP.[16] In characterizing these results Prof. Welch notes that "[T]he equity premium

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[13] Robert S. Harris and Felicia C. Marston (2001), "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (1) 6-16.

[14] Ibbotson, R. and P. Chen (2003), "Stock Market Returns in the Long Run: Participating in the Real Economy," *Financial Analyst Journal*, 59(1):88-98. Cited figures are on p. 97.

[15] Ivo Welch (2000), "Views of Financial Economists on the Equity Premium and on Professional Controversies," *Journal of Business*, 73(4):501-537. The cited figures are in Table 2 p. 514.

[16] Ivo Welch, 2001, "The Equity Premium Consensus Forecast Revisited," School of Management at Yale University working paper. The cited figure is in Table 2.

consensus forecast of finance and economics professors seems to have dropped during the last 2 to 3 years, a period with low realized equity premia."[17]

The above quotation from Prof. Welch emphasizes the caution that must attend survey data even from knowledgeable survey participants: the outcome is likely to change quickly with changing market circumstances. Regulators should not, in my opinion, attempt to keep pace with such rapidly changing opinions.

Third, some of the evidence for negative or close to zero market risk premium simply does not make sense. Despite relatively high valuation levels, stock returns remain much more volatile than Treasury bond returns. I am not aware of any empirical or theoretical evidence showing that investors would rationally hold equities and not expect to earn a positive risk premium for bearing the risk.

Fourth, I am unaware of a convincing theory for why the future MRP should have substantially declined. At the height of the stock market bubble in the U.S. and Canada, many claimed that the only way to justify the high stock prices would be if the MRP had declined dramatically,[18] but this argument is heard less frequently now that the market has declined substantially. All else equal, a high valuation ratio such as price-earnings ratio implies a low required rate of return, hence a low MRP. However, there is considerable debate about whether the high level of stock prices (despite the burst of the internet

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[17] *Ibid.*, p. 8.

[18] See Robert D. Arnott and Peter L. Bernstein (2002), "What Risk Premium is 'Normal'?", *Financial Analysts Journal* 58:64-85, for an example.

bubble in the last a couple of years) represents the transition to a new economy or is simply an "irrational exuberance," which cannot be sustained for the long term. If the former case is true, then the MRP may have decreased permanently. Conversely, the long-run MRP may remain the same even if expected market returns in the short-term are smaller.

Another common argument for a lower expected MRP is that the U.S. experienced very remarkable growth in the 20th century that was not anticipated at the start of the century. As a result, the average realized excess return is overestimated meaning the standard method of estimating the MRP would be biased upward. However, one recent study by Profs. Jorion and Goetzmann[19] finds, under some simplifying assumptions, that the so-called "survivorship bias" is only 29 basis points.[20] Furthermore, "[I]f investors have overestimated the equity premium over the second half of the last century, Constantinides (2002) argues that 'we now have a bigger puzzle on our hands'" Why have investors systematically biased their estimates over such a long horizon?[21]

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[19] Jorion, P., and W. Goetzmann (1999), "Global Stock Markets in the Twentieth Century," *Journal of Finance* 54:953-980.

[20] Dimson, Marsh, and Staunton (2003), "Global Evidence on the Equity Risk Premium," Journal of Applied Corporate Finance, 15, pp. 27-38 make a similar point when they comment on the equity risk premia for 16 countries based on returns between 1900 and 2001: "While the United States and the United Kingdom have indeed performed well, compared to other markets there is no indication that they are hugely out of line." p.4.

[21] Mehra, R., and E.C. Prescott (2003), "The Equity Premium in Retrospect," in *Handbook of the Economics of Finance*, Edited by G.M. Constantinides, M. Harris and R. Stulz, Elsevier B.V, p. 926

There are also a number of papers that argue that the MRP is variable and depends on a broad set of economic circumstances. For example, Mayfield (2004) estimates the MRP in a model that explicitly accounts for investment opportunities. He models the process that governs market volatility and finds that the MRP varies with investment opportunities which are linked to market volatility. Thus, the MRP varies with investment opportunities and about half of the measured MRP is related to the risk of future changes in investment opportunities. Based on this approach Mayfield estimates the U.S. MRP to be 5.6 percent measured since 1940.[22] However, the problem with such an approach is determining when the MRP has changed and by how much.

To sum up the above, I cite two passages from Profs. Mehra and Prescott's review of the theoretical literature on equity premium puzzle:[23]

> Even if the conditional equity premium given current market conditions is small, and there appears to be general consensus that it is, this in itself does not imply that it was obvious either that the historical premium was too high or that the equity premium has diminished.

> In the absence of this [knowledge of the future], and based on what we currently know, we can make the following claim: over the long horizon the equity premium is likely to be similar to what it has been in the past and the returns to investment in equity will continue to substantially dominate that in T-bills for investors with a long planning horizon.

**Q28. Is there other scholarly discussion on the value of the MRP?**

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22 E. Scott Mayfield (2004), "Estimating the market risk premium," Journal of Financial Economics 73, pp. 465-496.

23 Mehra, R., and E.C. Prescott, *op cit.*, p. 926.

A28. Yes. Another line of research was pursued by Steven N. Kaplan and Richard S. Ruback. They estimate the market risk premium in their article, "The Valuation of Cash Flow Forecasts: An Empirical Analysis."[24] Professors Kaplan and Ruback compare published cash flow forecasts for management buyouts and leveraged recapitalization over the 1983 to 1989 period against the actual market values that resulted from these transactions. One of their results is an estimate of the market risk premium over the long-term Treasury bond yield that is based on careful analysis of actual major investment decisions, not realized market returns. Their median estimate is 7.78 percent and their mean estimate is 7.97 percent.[25] This is considerably higher than my estimate of 6.5 percent for the U.S. Even if the maturity premium of Treasury bonds over Treasury bills were only 1 percent, well below the best estimate of 1.5 percent, the resulting estimate of the market risk premium over Treasury bills is higher than my estimate of 8.0 percent for the U.S. Because the capital markets in the U.S. and Canada are becoming increasingly integrated, the MRP in Canada will be affected by the investment opportunities in the U.S. and the rest of the world as is discussed extensively in Dr. Kolbe's evidence.

**Q29. What is your conclusion regarding the MRP?**

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[24] *Journal of Finance*, 50, September 1995, pp. 1059-1093.

[25] *Ibid*, p. 1082.

A29. Much of the recent controversy over market risk premium has centered on various issues suggesting that the market risk premium may not be as high as frequently estimated in the past. Although none of the arguments are completely persuasive in themselves, I decided to give some weight to the issues in the dispute and in 2003 in my previous evidence before the NEB in RH-2-2004, I reduced my estimate of the market risk premium for Canada by 50 basis points from values I relied upon previously. Considering all the evidence, I conclude that S&P/TSX stocks of average risk today command a premium of about 5.25 percent over the long-term government bond yield. This represents a decrease in my estimate of the MRP by an additional 25 basis points in recognition of the ongoing controversy in this area for a total reduction of 75 basis points from my first appearance in Canada in 1999. This adjustment results in a conservative estimate of the MRP that is fully consistent with the historical evidence in Canada and the mixed theoretical evidence.

### 2. Relative Risk

**Q30. How do you measure relative risk?**

A30. The risk measure I examine is the "beta" of the stocks in question. Beta is a measure of the "systematic" risk of a stock — the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

**Q31. Please explain beta in more detail.**

A31. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that *cannot* be eliminated by diversification.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order of 15-20 percent per year.[26] But many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15-20 percent because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return — positive or negative — is usually less extreme than that of individual stocks within it.

In the limiting case, if the returns on individual stocks were completely uncorrelated with one another, the formation of a large portfolio of such stocks would eliminate risk entirely. That is, the market's long-run standard deviation would be not 15-20 percent per year, but virtually zero.

The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks *are* correlated with one another, and to a material

[26] See Brealey, Myers and Allen, *op. cit.*, p. 158.

degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus some risk is "non-diversifiable". Single-factor equity risk premium approach models derive conditions in which all of these factors can be considered simultaneously, through their impact on the market portfolio. Other models derive somewhat less restrictive conditions under which several of them might be individually relevant.

Again, the basic idea behind all of these models is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification, because there are a large number of large portfolios whose managers actively seek the best risk-reward tradeoffs available. Of course, undiversified investors would like to get a premium for bearing diversifiable risk, but they cannot.

**Q32. Why not?**

A32. Well-diversified investors compete away any premium rates of return for diversifiable risk. Suppose a stock were priced especially low because it had especially high diversifiable risk. Then it would seem to be a bargain to well diversified investors. For example, suppose an industry is subject to active competition, so there is a large risk of loss of market share. Investors who held a portfolio of all companies in the industry would be immune to this risk, because the loss on one company's stock would be offset by a gain on another's stock. (Of course, the competition might make the whole industry more vulnerable to the business cycle, but the issue here is the diversifiable risk of shifts in market share among firms.)

If the shares were priced especially low because of the risk of a shift in market shares, investors who could hold shares of the whole industry would snap them up. Their buying would drive up the stocks' prices until the premium rates of return for diversifiable risk were eliminated. Since all investors pay the same price, even those who are not diversified can expect no premium for bearing diversifiable risk.

Of course, substantial non-diversifiable risk remains, as the October Crash of 1987 demonstrates. Even an investor who held a portfolio of all traded stocks could not diversify against that type of risk. Sensitivity to such market-wide movements is what beta measures. That type of sensitivity, whether considered in a single- or multi-factor model, determines the risk premium in the cost of equity.

**Q33. What does a particular value of beta signify?**

A33. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

**Q34. How is beta measured?**

A34. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Many investment services report betas, including *FPinfomart*,[27] Merrill Lynch's quarterly *Security Risk Evaluation* and the *Value Line Investment Survey*. Betas are not always calculated the same way, and therefore must be used with a degree of caution, but the basic point that a high beta indicates a risky stock has long been widely accepted by both financial theorists and investment professionals.

**Q35. Are there circumstances when the "usual approach" should not be used?**

A35. There are at least two cases where the standard estimate of beta should be viewed skeptically.

First, companies in serious financial distress seem to "decouple" from their normal sensitivity to the stock market. The stock prices of financially distressed companies tend to change based more on individual news about their particular circumstances than upon overall market movements. Thus, a risky stock could have a

[27] Beta estimates from FPinfomart are not publicly available. FPinfomart.ca is an online media monitoring service that offers timely, reliable and in-depth access to Canada's news and business sources.

low estimated beta if the company was in financial distress. Other circumstances that may cause a company's stock to decouple include an industry restructuring or major changes in a company's supply or output markets.

Second, similar circumstances seem to arise for companies "in play" during a merger or acquisition. Once again, the information about the progress of the proposed takeover is so much more important for that individual stock than day-to-day market fluctuations that, in practice, beta estimates for such companies seem to be too low.

**Q36. How reliable is beta as a risk measure?**

A36. Scholarly studies have long confirmed the importance of beta for a stock's required rate of return. It is widely regarded as the best single risk measure available. The merits of beta seemed to be challenged by widely publicized work by Professors Eugene F. Fama and Kenneth R. French. However, despite the early press reports of their work as signifying that "beta is dead," it turns out that beta was still a potentially important explanatory factor (albeit one of several) in their work. Thus, beta remains alive and well as the best single measure of relative risk.

### 3. Interest Rate Forecast

**Q37. What interest rates do your procedures require?**

A37. Modern capital market theories of risk and return use the short-term risk-free rate of return as the starting benchmark, but regulatory bodies frequently use a version of the risk positioning model that is based upon the long-term risk-free rate. In this proceeding, I rely upon the long-term version of the risk positioning model. Accordingly, the implementation of my procedures requires use of a forecast of the long-term Canadian Government bond rate. I obtain this information from *Consensus Forecasts*.

## C. DISCOUNTED CASH FLOW METHOD

**Q38. Do you provide cost of equity estimates using the DCF model?**

A38. Yes.

**Q39. Please describe the discounted cash flow approach.**

A39. The DCF model takes the first approach to cost of capital estimation, i.e., to attempt to estimate the cost of capital in one step. The method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method is described in detail in Appendix C.

**Q40. What are the merits of the DCF approach?**

A40. The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence so unlikely to correspond to reality.

Finding the right growth rate(s) is the usual "hard part" of a DCF application. The original approach to estimation of $g$ relied on average historical growth rates in observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates $g$ as the average book rate of return times the fraction of earnings retained within the firm. But it is highly unlikely that historical averages over periods with widely varying rates of inflation and costs of capital will equal current growth rate expectations.

A better approach is to use the growth rates currently expected by investment analysts, if an adequate sample of such rates is available. If this approach is feasible and if the person estimating the cost of capital is able to select the appropriate version of the DCF formula, the DCF method should yield a reasonable estimate of the cost of capital for companies not in financial distress, subject to the additional concerns described in Appendix C. However, for the DCF approach to work, the basic stable-growth assumption must become reasonable and the underlying stable-growth rate must become determinable *within the period for which forecasts are available*.

In short, the unavoidable questions about the DCF model's strong assumptions cause me to view the DCF method as *inherently* less reliable than risk positioning approach described above.

**Q41. What weight do you give to the results of the DCF model in this proceeding?**

A41. Because the DCF method has been widely used in the past and in other forums when the industry's economic conditions were different from today's, I submit DCF evidence in this case. I give little weight to the DCF results for either sample, but the DCF estimates serve as a check on the values provided by the risk positioning methods.

## IV. COST OF CAPITAL ESTIMATES FOR THE BENCHMARK SAMPLES

**Q42. How is this section of your written evidence organized?**

A42. As noted in *Section II*, I estimate the cost of capital using two samples of comparable risk companies. This section first covers matters such as sample selection, market-value capital structure determination, and the sample companies' costs of debt and preferred equity. It then covers estimation of the cost of equity for the sample companies and the resulting estimates of the sample's overall after-tax cost of capital. Next, it analyzes these data to reach a conclusion on the deemed equity component at the OEB's formula-determined rates of return on equity for both of the benchmark samples.

## A. PRELIMINARY DECISIONS

**Q43. What preliminary decisions are needed to implement the above principles?**

A43. I must select the benchmark samples, calculate the sample companies' market-value capital structures, and determine the sample companies' market costs of debt and preferred equity.

### 1. The Samples: Canadian Utilities and U.S. Gas Local Distribution Companies

**Q44. Why is it necessary to use two samples?**

A44. The overall cost of capital for a part of a company depends on the risk of the lines of business in which the *part* is engaged, *not* on the overall risk of the parent company on a consolidated basis. According to financial theory, the overall risk of a diversified company equals the market-value weighted average of the risks of its components.

Estimating the deemed capital structure for Union that is consistent with the market-derived information on the cost of capital is the subject of this evidence. The ideal sample for that task would be a large number of companies that are publicly traded "pure plays" in the natural gas distribution, storage and transmission lines of business. "Pure play" is an investment term referring to companies with operations only in one line of business. Publicly traded firms, firms whose shares are freely traded on stock exchanges, are ideal because the best way to infer the cost of capital is to examine evidence from capital markets on companies in the given line of business. In this case, a sample of companies whose operations are concentrated solely in the natural gas distribution, storage and transmission lines business would be ideal.

The number of publicly traded natural gas distribution companies in Canada is small, but there is a large number of relatively "pure" gas distribution companies in the U.S. Therefore, Dr. Kolbe and I select a sample of Canadian utilities and a set of U.S. gas LDC companies as benchmarks. The sample selection process proceeds as follows. First, a sample of Canadian utilities is used to assess the risks for Canadian utilities in general. Second, a sample of U.S. companies whose operations are concentrated in the regulated natural gas distribution business is used. Unlike the Canadian utility sample, all companies in the gas LDC sample have operations concentrated in the natural gas distribution industry just as does Union. Therefore, I believe it is a particularly good benchmark for the Company in this proceeding, but to the degree that there are differences in risk between either of the benchmark samples and the Company's lines of business, Dr. Kolbe will take that into consideration as he considers the sample evidence and Dr. Carpenter's evidence on the business risks of the Company.

Additional details of the sample selection process for each sample are described below as well as in Appendix B.

**Q45. How do you ensure that the evidence from U.S sample companies is consistent with Canadian capital markets?**

A45. I ensure consistency with the Canadian capital markets by combining the risk measures (beta) of the U.S. gas LDC companies with Canadian capital market parameters to estimate the sample's average overall after-tax weighted-average cost of capital. Beta is a measure of the relative risk of a company compared to the risk of an average stock in the market as discussed above in Section III-B.2. In other words, I use the Canadian risk-free interest rate, tax rates, interest rates on utility bonds and market risk premium to estimate the cost of equity for the gas LDC sample companies. The result is cost of capital estimates for the gas LDC sample as if their stocks were trading in Canadian capital markets with a relative risk as measured by the companies' betas.

Note that the DCF estimates for the gas LDC sample are estimates of the cost of equity in the U.S. capital markets. This is one more reason that I do not put great weight on the DCF estimates for the gas LDC sample.

### 2. Market-Value Capital Structure

**Q46. What capital structure information do you require?**

A46. For reasons discussed in Dr. Kolbe's written evidence and explained in detail in his Appendix B, explicit evaluation of the market-value capital structures of the sample companies is vital for a correct interpretation of the market evidence on the return on equity. This requires estimates of the market values of common equity, preferred equity and debt, and the current market costs of preferred equity and debt.

**Q47. Please describe how you calculate the market values of common equity, preferred equity and debt.**

A47. I determine the capital structure for each company by estimating the market values of common equity, preferred equity and debt from the most recent publicly available data. The details are in Appendix B.

Briefly, the market value of common equity is the price per share times the number of shares outstanding. For the risk positioning approach, I use the average price of the last five trading days of each year to calculate the market value of equity for the year. I then calculate the average capital structure over the corresponding five year period used to estimate the "beta" risk measures for the gas LDC sample companies. This procedure matches the estimated beta to the degree of financial risk present during its estimation period. For the Canadian sample, I use the average capital structure of the most recent period (January 2006) and the year-end 2004 capital structure which corresponds to the estimation period for the 52-week beta estimates. In the DCF analyses, I use the average stock price over 15 trading days ending on the release date of the Institutional Brokers' Estimate System[28] ("IBES") growth rate forecasts utilized in the

[28] IBES is a system that gathers and compiles estimates made by stock analysts on the future earnings for the (continued...)

DCF analysis to estimate the capital structure at the time of the release of the earnings estimates.[29]

The market value of debt for the companies in the U.S. sample is estimated at its book value, because market and book values of debt currently do not differ much in the U.S. For the companies in the Canadian sample, the market value of debt is estimated using each company's embedded interest expense discounted at the current market yield on comparably rated bonds and assuming a ten year maturity for repayment of principal.[30] The market value of preferred stock for the samples is set equal to its book value because the market values and book values do not vary much and because the percent of preferred stock in the capital structure is relatively small compared to the debt and common equity components.

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[28] (...continued)
majority of U.S. publicly traded companies. IBES provides a central location whereby investors are able to research different analyst estimates for any given stock without necessarily searching for each individual analyst. Growth forecasts for the Canadian utility companies are from the Globe and Mail's webpage. The webpage sources Thompson Research.

[29] January 3, 2006 for the Canadian utility sample and December 16, 2005 for the U.S. gas LDC sample.

[30] The assumption of a ten year maturity is a simplification. Currently, the bonds with the highest embedded costs are also generally those issued farthest in the past. Bonds issued more recently have embedded costs which are closer to the current market rates of interest. The ten year maturity assumption is designed to capture the market value of the bonds with embedded costs different from market interest rates, but also recognizes that the oldest bonds are also those likely to be repaid sooner. The market value of bonds with a floating interest rate were set equal to its book value and preferred securities listed among the company's debt instruments were treated as debt.

### 3. Market Costs of Debt and Preferred

**Q48. How do you estimate the current market cost of debt?**

A48. For both samples, the market cost of debt for each company used in the analysis is the current yield (for the DCF models) on an index of utility bonds corresponding to the company's current debt rating (or the average debt rating over the beta estimation period for the risk positioning models). The companies' bond ratings are reported by Compustat for the U.S gas LDC sample and by Dominion Bond Rating Service for the Canadian Utility sample.[31]

Note that for the firms in the U.S. sample, the bond rating reported by Compustat for each company is used with the estimated current yield data on Canadian bonds of an equivalent rating. Calculation of the after-tax cost of debt uses Union's estimated marginal income tax rate of 36.12 percent.

**Q49. How do you estimate the market cost of preferred equity?**

A49. For both samples, the cost of preferred equity is set equal to the cost of debt on Canadian utility bonds of a comparable rating. There is to my knowledge no public source for

[31] The Standard & Poor's Compustat North America is a subscription database that covers over 21,000 active and inactive U.S. and Canadian companies. It has up to 20 years and 48 quarters of history. It provides income statement, balance sheet and statement of cash flow items, monthly stock price data, business segment data, geographic segment data and company address and name information. Dominion Bond Rating Services (www.dbrs.com) is a Canadian bond rating agency that rates issuers of bonds, commercial paper, etc.

yields on preferred equity by preferred rating in Canada.[32] The cost of preferred is likely to be somewhat higher than the after-tax cost of debt but lower than the pre-tax cost of debt, but because the amount of preferred equity in the capital structures of the Canadian sample companies average about two percent (four percent for the subsample) and less than one percent for the U.S. companies, this approximation will have a minimal impact on the overall results.[33]

## B. THE BENCHMARK SAMPLES

### 1. Canadian Utility Sample Selection

**Q50. How did you select your sample of Canadian utilities?**

A50. To construct this sample, I started with the universe of Canadian companies classified as being in the utility industry in the FPinfomart database.[34] I eliminated companies that were not listed in the FP500 Sales category on FPinfomart which eliminated a number of smaller companies. I then applied additional selection criteria designed to narrow the sample to companies with characteristics similar to that of Union. I also eliminated companies with unique circumstances which may bias the cost of capital estimates. The

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[32] Note that preferred securities for the sample companies are treated as debt because the dividend payments are deductible for corporate income tax purposes.

[33] Union Gas has 3.2 percent (tax deductible) preferred securities in its proposed regulatory capital structure.

[34] The information was extracted on January 3, 2006 from www.fpinformart.ca.

final sample consists of five companies (Canadian Utilities, Enbridge, TransCanada, Fortis, and Gaz Metro LP) for the risk positioning estimates, and five companies (Canadian Utilities, Emera, Enbridge, TransCanada, and Fortis) for the DCF analysis, because I know of no source providing long-term earnings growth estimates for Gaz Metro LP. Emera is not included in the risk positioning analysis because its estimated beta is only 0.06 which is equivalent to a risk-free asset and is clearly not a reasonable measure of the risk of the company. Additional details of the Canadian sample selection process are in Appendix B.

**Q51. Do you include utility income trusts in your Canadian utility sample?**

A51. No. The utility income trusts have special characteristics that make them unsuitable for estimating the cost of capital for corporate utilities.

### 2. U.S. Gas Local Distribution Sample Selection

**Q52. How do you select your sample of U.S. gas local distribution companies?**

A52. One reason for use of the gas LDC sample is to generate a sample of regulated companies whose primary source of revenues is in the regulated portion of the natural gas distribution industry. Therefore, I started with the universe of publicly traded gas distribution utilities covered by *Value Line* and required the sample companies to have revenues from regulated natural gas distribution that is 50 percent or more of total revenue. The final sample includes eight companies. I also report results for a subsample of four companies that have more than 70 percent of their revenue from regulated activities during the last full year of available data. Appendix B discusses the selection process for the U.S. gas LDC sample in more detail.

**Q53. Please compare the characteristics of the Canadian utility sample and the U.S. gas LDC sample.**

A53. In terms of percentage of revenues from regulated operations, the two samples are very similar. They differ primarily in the fact that the U.S. gas LDC sample is concentrated in one segment of the regulated natural gas industry while the Canadian sample consists of companies in the electric, natural gas pipeline, natural gas distribution and petroleum industries. Therefore, it is more difficult to determine the risk of any single industry using the Canadian sample because differences in estimated cost of capital among the sample companies could be due to differences in industry risk as well as other factors. In addition, the Canadian sample results are potentially affected by the recent increase in the amount of merger activities involving companies in the sample, as well as by the difficulty in estimating beta for the sample companies.[35] The gas LDC sample does not

[35] For example, Fortis remains in the Canadian sample even though it has recently been involved in an acquisition because removing it would leave only five companies in the sample. Emera's is not part of the risk positioning analysis because its estimated beta is 0.06 which results in a CAPM estimate of the cost of equity less than its cost of debt.

suffer from these weaknesses. Please refer to Appendix B for additional details comparing the two samples.

## C. RISK POSITIONING COST OF CAPITAL ESTIMATES

**Q54. How is this section of your evidence on the risk positioning approach cost of capital estimates organized?**

A54. This section first describes the input data used in the CAPM and ECAPM models, then reports the resulting cost of equity estimates for the samples. Appendix B provides additional details on the empirical analysis.

### 1. Interest Rate Forecasts

**Q55. How do you determine the expected risk-free interest rate?**

A55. I obtain the forecast of the long-term risk-free rates on government bonds from the survey information available from Consensus Economics, Inc., a London based forecasting survey firm. *Consensus Forecasts* provides forecasts of the 3-month Treasury bill rate and the 10-year government bond rate. The Consensus Economics forecasts for the year ending January 2007 show that both short-term and long-term interest rates are expected to increase in the coming year over current rates. The 3-month Canadian Government bond yield is forecast to be about 4.00 percent and the long-term interest rates are expected to be about 4.80 percent including a 20 basis point maturity premium.[36] I add a maturity premium of 20 basis points to the 10-year government yield to reflect the additional yield required for bonds of longer maturity.[37]

**Q56. Why is it necessary to add a maturity premium to the forecast of the 10-year bond yield?**

A56. The addition of the maturity premium is necessary for consistency so that the average bond maturities in the data used to estimate the long-term market risk premium correspond to the maturity of the benchmark for the long-term risk-free rate.[38]

The maturity premium represents the extra return investors demand for tying up their money for longer periods. The *Report on Canadian Economic Statistics 1924-2004* released by the Canadian Institute of Actuaries in March 2005 reports data on three-month, one-to-three-year, three-to-five-year, five-to-ten year, and long-term Government yields from 1951 through 2004. I use these data to infer a set of maturity premiums for intermediate maturities. See Workpaper #2 to Table No. MJV-9 for details.

[36] *Consensus Forecasts*, January 9, 2006.

[37] The average term to maturity is reported to be 18 years for the yields provided in the Report on Canadian Economic Statistics 1924-2004.

[38] The 20 basis point addition is a conservative estimate of the premium that investors require to hold bonds with a maturity of 18 years instead of bonds with a maturity of 10 years. The estimate is derived from a yield curve constructed from the historical average maturity premiums of Canadian Government bonds from 1951 through 2004 for bonds with five different average maturities.

**Q57. What value do you use for the risk-free interest rate in your risk-positioning model?**

A57. I use a value of 4.80 percent for the long-term risk-free interest rate as the benchmark interest rates in the risk positioning analyses. I do not rely on the short-term version of the risk-positioning model in this proceeding.

### 2. Betas and the Market Risk Premium

**Q58. How do you normally calculate beta?**

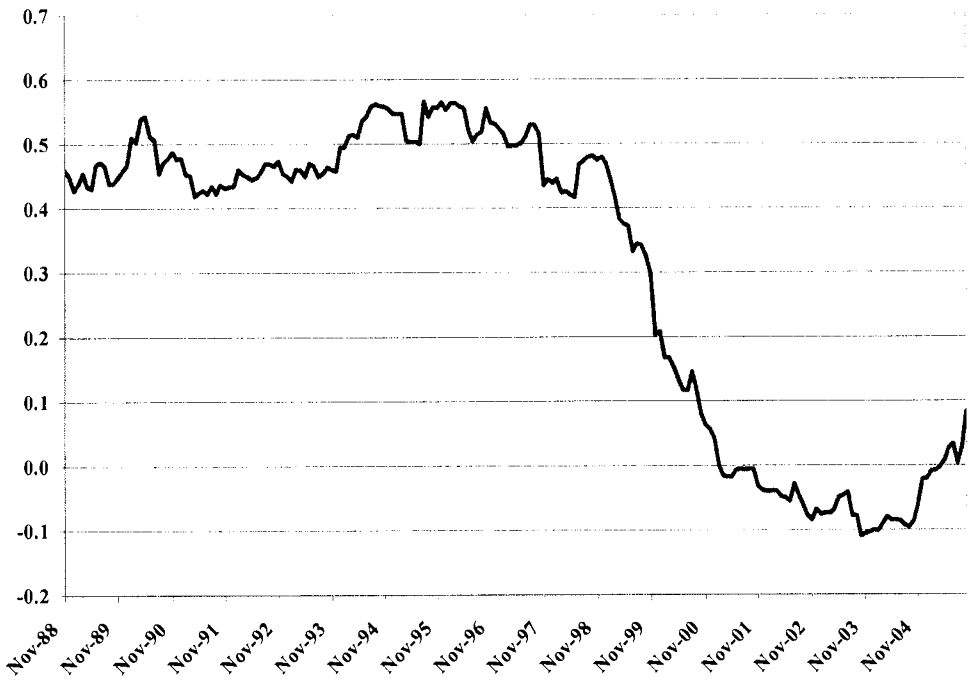
A58. My standard approach is to calculate beta by statistical regression of the excess (positive or negative) of the return on the stock over the risk-free rate against the excess return over the risk-free rate on either the S&P/TSX index for the Canadian companies or the S&P 500 index for the U.S. companies. I normally use monthly return data for the most recent 60-month period for which data exist, but the turmoil and unusual events in the stock market makes the most recent 60 month period unsuitable to estimate the sample companies' betas. These events have caused the returns of the companies in the two samples to "decouple" from their normal relationship to the returns on the market indices. I believe that the risk of the sample companies has increased given the changes in the natural gas market and the restructuring in the electric industry, but betas estimated over the most recent 60 month period have fallen dramatically for both samples from estimates based upon data from only a few years earlier. Several of the estimated betas for individual company in both samples were very close to zero for the most recent 60 month period. These results caused me to question of the validity of the estimates, and I was forced to rely on alternative methods to estimate betas which I describe below.

**Q59. What evidence do you have that the betas estimated over the most recent 60 months are unusual?**

A59. Displayed in Figures 3 and 4 below are the estimated average betas of the Canadian and U.S. gas LDC samples respectively for the period November 1988 to October 2005. These betas are estimated on 60 months of return data using the S&P/TSX or the S&P 500 indices and the 30-day T-bill returns. These are "rolling betas" which means that the estimated beta in each calendar month is based upon the previous 60 months of return data. In this way, the changes in the estimated betas can be tracked through time.

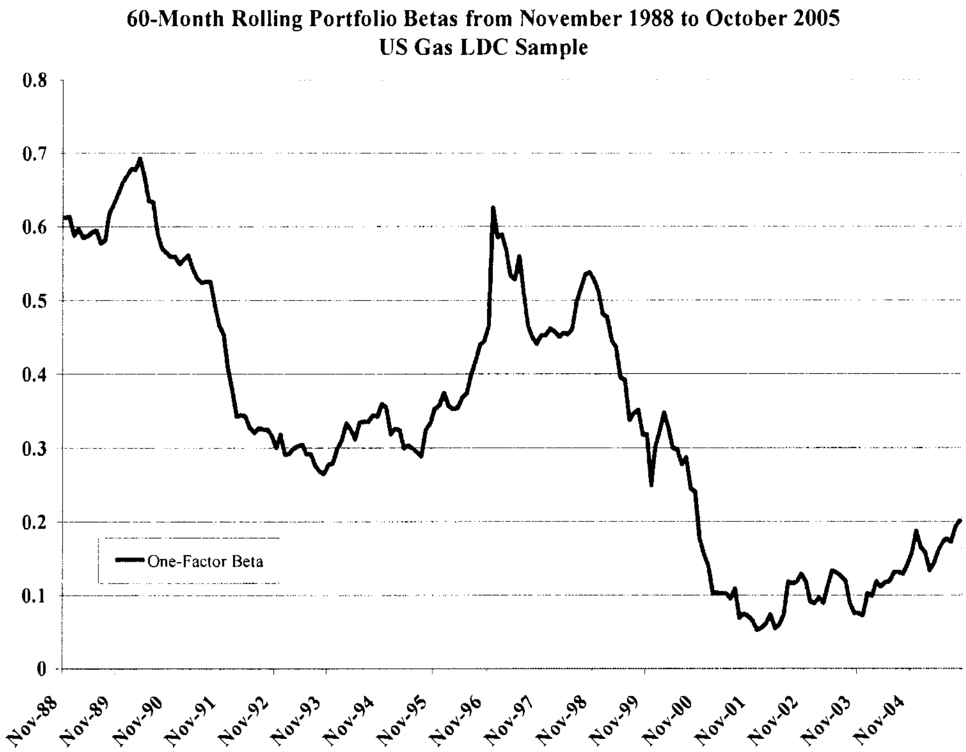
**Figure 3**

**60-Month Rolling Portfolio Betas from November 1988 to October 2005**
**Canadian Utilities Sample**




As can be easily seen in the figures, the estimated betas for both samples have declined dramatically during the last few years. Although the estimated betas were variable in the previous periods, the average for the Canadian sample seemed to be centered around a relatively stable value. As a very rough estimate, the estimated average beta for the Canadian sample seemed to vary around a value of about 0.40 to 0.55. For the U.S. gas LDC sample, the sample average beta varies to a much greater extent between about 0.30 to 0.70. However, the October 2005 average estimated beta was about 0.08 for the Canadian utility sample and about 0.20 for the U.S. gas LDC sample. Neither estimate is statistically significant. A beta value of zero is equivalent to a risk-free asset and is clearly not representative of the risk of the companies in either the Canadian or the U.S gas LDC sample.

**Figure 4**




**Q60. Do you believe that this is evidence of the "decoupling" that you mentioned earlier?**

A60. Yes. Because I do not believe that these beta estimates are an accurate measure of the relative risk of the sample companies, I modify the computation of betas for this proceeding.

**Q61. In light of decoupling illustrated in Figures 3 and 4 of your evidence, how do you estimate the betas for the two samples?**

A61. In this case, I rely upon betas estimated by *Value Line* for the gas LDC sample. I have reviewed the betas estimated by *Value Line,* and the estimated values declined only very slightly over the last few years and have now returned to their previous levels as opposed to the dramatic decline that resulted from my standard estimation procedures illustrated in Figure 4 above. *Value Line* uses 5 years of weekly return data (a 60 month period) but uses a different method to estimate beta than the 60 months of monthly returns than I would normally use. *Value Line* does not reveal the full details of its estimation process, but the recent beta estimates show that *Value Line* seems to agree that the risk of these sample companies has not suddenly declined. The betas reported by *Value Line* are adjusted betas, so I reverse the process to get "unadjusted" values for use in the models for the companies in the U.S. sample.

*Value Line* does not report betas for all of the companies in the Canadian sample, and because I know of no publicly-available alternative source (such as *Value Line*) for 60-month beta estimates for the Canadian sample that did not also estimate current betas that were either very close to zero or even negative for most companies, I was forced to use an alternative approach to estimate betas for the Canadian sample.

**Q62. How do the unadjusted and adjusted betas for the U.S. gas LDC sample compare?**

A62. The *Value Line* adjusted betas for the U.S. gas LDC sample range from 0.65 to 0.85 resulting in unadjusted betas that range from 0.45 to 0.75 (See Workpaper #1 to Table No. MJV-20) with a sample average of 0.64. The sample average beta value is very close to the beginning value for the sample for the period prior to the recent decline in estimated betas as can be seen in the graph of rolling average betas displayed in Figure 4.

**Q63. Why do you "unadjust" the *Value Line* betas?**

A63. Adjustment moves betas one-third of the way toward a value of one, the average stock beta. The adjustment is designed as a correction for the tendency of companies with low estimated betas to have negative sampling errors and for the tendency of companies with high estimated betas to have positive sampling errors.

Companies regulated on the basis of original cost rate base frequently display unusual sensitivity to interest rate changes in a manor similar to bonds. I use adjusted betas when the sample companies display such unusual sensitivity but that is not the case for the companies in either sample at this time, so I believe that unadjusted betas are a better estimate of the relative risk of the sample companies.

**Q64. If you can't rely upon *Value Line* for betas for the Canadian sample, how do you estimate betas for the Canadian sample in this proceeding?**

A64. For the Canadian sample, I calculate the betas by regressing the excess (positive or negative) of the return on the stock over the risk-free rate against the excess of the return on the S&P/TSX over the risk-free rate using 52 weeks of available data.

**Q65. Please discuss the Canadian 52-week beta estimates.**

A65. The 52-week beta estimates for the period that ends December 21, 2005 are displayed in Workpaper #1 to Table No. MJV-10. Omitting the estimate for Emera, the betas range from 0.24 to 0.80. Emera's estimate is 0.06 which is clearly not a reasonable estimate of the risk of the company. The sample average beta is 0.47 including Emera in the average and 0.56 without Emera. These values are about in the middle of the range of the 60-month beta values displayed in Figure 3 before the recent decline.

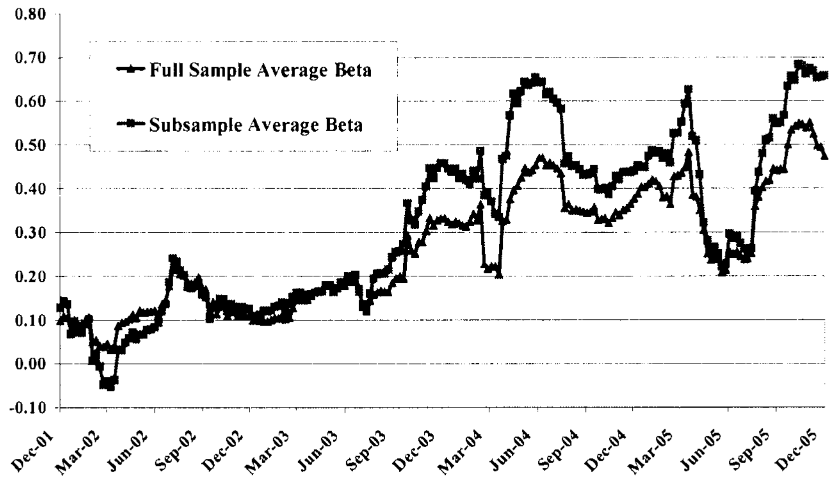
**Q66. Are you satisfied that the 52-week betas for the Canadian sample are completely reliable?**

A66. No. As can be seen in Figure 5 below, the sample average 52-week beta estimates are highly unstable for both the full Canadian sample and the subsample. This made me skeptical of relying on 52-week betas for any particular 52 week period of time. Instead, I have fitted linear trend lines to the data as shown in Figure 6 below. The linear trend lines are highly statistically significant, but they have the troubling implication that the beta of the sample companies will continue to increase without limit over time. Logically, one would expect that the average beta of the sample would approach a value more consistent with historical estimates, so I fitted a curve trend line to the data. This curve for the subsample is shown in Figure 6 as the concave curved dashed line and is also highly statistically significant. The full sample did not display statistically significant curvature.

Note that this procedure results in a single beta for the full sample and a single beta for the subsample because I am using the average of the sample betas to estimate the trend lines.

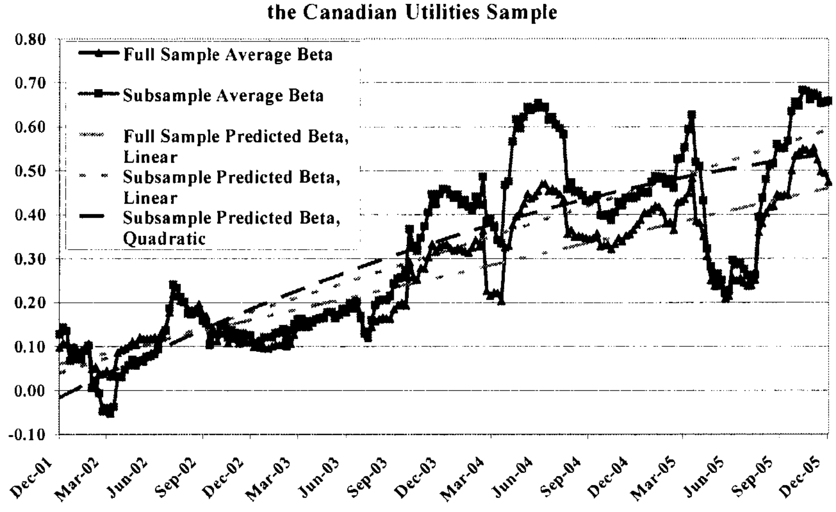
## Figure 5

**52-Week Rolling Betas from December 2001 to December 2005 for the Canadian Utilities Sample**




## Figure 6

**52-Week Rolling Betas from December 2001 to December 2005 for the Canadian Utilities Sample**



**Q67. What beta values do you use in your analysis of the Canadian utility sample?**

A67. I use the values predicted by the linear trend line for the full sample and the curved trend line for the subsample for the period ending December 2006. The values are 0.56 for the full sample and 0.57 for the subsample (not including Emera). These values are also displayed in Workpaper #1 to Table No. MJV-10. I believe that these are the best estimates of the relative risk of the Canadian sample companies currently available.

**Q68. What value do you use for the market risk premium?**

A68. I use a premium over the long-term risk-free interest rate of 5.25 percent for the reasons discussed above.

### 3. Risk Positioning Estimates for the Canadian Utility Sample

**Q69. What are the cost of equity and overall cost of capital estimates for the Canadian sample using the risk positioning approach?**

A69. Using the long-term risk-free rate in the two risk positioning models (CAPM and ECAPM) and using two different values for the ECAPM parameter, $\alpha$, (one and two percent) I obtain three estimates of the cost of equity for the full sample and the subsample. These estimates are displayed in columns 4-6 of Table No. MJV-10. The cost of equity estimates are combined with the information on the market cost of debt and preferred and the average market-value capital structure to estimate the sample average

ATWACC for the full sample and the subsample. These values are displayed in Panels A-C of Table No. MJV-11.

**Q70. What procedure do you use to determine the deemed equity component for each of the sample's average ATWACC?**

A70. Knowing the cost of equity, the cost of debt, the cost of preferred, the amount of preferred in the capital structure and the marginal tax rate, I can calculate the percentages of equity and debt in the capital structure that has the same ATWACC as estimated by each of the different cost of equity estimation methods. This is the equity thickness that is reported in the tables below and in Table No. MJV-12, Panels A-D.

**Q71. What are the estimates of the deemed equity component derived from the risk positioning approach for the Canadian sample?**

A71. Using the long-term risk-free rate in the two risk positioning models (CAPM and ECAPM) and using two different values for the ECAPM parameter, $\alpha$, (one and two percent) I obtain three estimates of the sample's average ATWACC and the deemed equity component at a 9.63 or 8.89 percent rate of return on equity. To guard against the results being biased by a few companies' unusual circumstances, the averages for these tables is computed using only those companies whose cost of equity estimated by the CAPM is larger than their cost of debt plus 25 basis points. This is a common sense measure that recognizes that a company's equity is riskier than its debt. Any estimate of the cost of equity that does not exceed the cost of the company's own debt plus 25 basis points fails this common sense notion. In this case, it means that Emera was dropped from the sample because the 52-week estimated beta for Emera is only 0.06.

The resulting after-tax weighted-average cost of capital and the deemed equity values are shown in Table 1. Panel A shows the ATWACC and deemed equity component for all Canadian sample companies whose cost of equity estimated by the CAPM is greater than its cost of debt plus 25 basis points. Panel B shows the results for the subsample companies with no dividend cuts or significant mergers for the past five years.

**Table 1: Panel A**

**Canadian Regulated Utility Sample**
**Risk Positioning After-Tax Weighted-Average Cost of Capital and**
**Deemed Equity Estimates for All Sample Companies**
**(CAPM RoE > Cost of Debt plus 25 basis points)**

| **Using Long-Term Risk-Free Rate** | **ATWACC** | **Deemed Equity Percent** | |
|---|---|---|---|
| | | **(9.63% RoE)** | **(8.89% RoE)** |
| CAPM | 5.7% | 39.3% | 44.4% |
| ECAPM ($\alpha$ = 1%) | 5.9% | 42.9% | 48.4% |
| ECAPM ($\alpha$ = 2%) | 6.2% | 46.5% | 52.5% |

Source: Table No. MJV-12, Panel A and Panel B.

**Table 1: Panel B**

**Canadian Regulated Utility Sample**
**Risk Positioning After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for Companies with No Dividend Cuts or Merger**
**(CAPM RoE > Cost of Debt plus 25 basis points)**

| Using Long-Term Risk-Free Rate | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63% RoE) | (8.89% RoE) |
| CAPM | 5.7% | 40.1% | 45.2% |
| ECAPM ($\alpha$ = 1%) | 6.0% | 43.7% | 49.3% |
| ECAPM ($\alpha$ = 2%) | 6.2% | 47.3% | 53.4% |

Source: Table No. MJV-12, Panel C and Panel D.

#### 4. Risk Positioning Estimates for the Gas LDC Sample

**Q72. What are the cost of equity and overall cost of capital estimates for the gas LDC sample using the risk positioning approach?**

A72. Because I have beta estimates for each individual company, I obtain three estimates of the cost of equity for *each* sample company using the long-term risk-free rate in the two risk positioning models (CAPM and ECAPM) and using two different values for the ECAPM parameter, $\alpha$, (one and two percent). These estimates are displayed in columns 4-6 of Table No. MJV-20. The cost of equity estimates are combined with the information on the market cost of debt and preferred and the market-value capital structure to estimate the ATWACC for each sample company. These values are displayed in Panels A-C of Table No. MJV-21. The sample average ATWACC for the full sample and the subsample are displayed at the bottom of the tables. In a manner identical to that for the Canadian sample, I calculate the percentages of equity and debt in the capital structure that has the same sample average ATWACC as estimated by each of the different cost of equity estimation methods. This is the equity thickness that is reported in the tables below and in Table No. MJV-22.

**Q73. What are the deemed equity estimates resulting from risk positioning model for the U.S. sample companies?**

A73. As with the Canadian sample, the data are used to obtain three deemed equity component estimates for risk premium approach. In particular, note that the risk positioning method for the for the U.S. sample utilizes Canadian, not U.S., capital market parameters. This calculation provides deemed equity estimates for companies with the relative risk of the U.S. natural gas distribution industry as if as if they were in the Canadian capital market setting.

The resulting ATWACC values and capital structure estimates at 9.63 and 8.89 percent rates of return on equity are shown in Table No. MJV-22, Panels A-D and in Table 2 below. Panels A of Table 2 is for the full sample, and Panel B is for the subsample of the gas LDC sample. As the tables show, the deemed equity estimates for the U.S. subsample are very nearly the same as for the Canadian subsample.

**Table 2: Panel A**

**U.S. Gas LDC Sample**

**Risk Positioning After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for All Sample Companies**

| Long-Term Risk-Free Rate | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63% RoE) | (8.89% RoE) |
| CAPM | 6.1% | 45.5% | 51.4% |
| ECAPM ($\alpha = 1\%$) | 6.3% | 48.7% | 55.0% |
| ECAPM ($\alpha = 2\%$) | 6.5% | 51.9% | 58.6% |

Source: Table No. MJV-22, Panel A and Panel B.

**Table 2: Panel B**

**U.S. Gas LDC Sample**
**Risk Positioning After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for Companies with Revenues from Regulated Activities of > 70 percent.**

| Long-Term Risk-Free Rate | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63% RoE) | (8.89% RoE) |
| CAPM | 5.9% | 43.1% | 48.7% |
| ECAPM ($\alpha = 1\%$) | 6.1% | 46.3% | 52.2% |
| ECAPM ($\alpha = 2\%$) | 6.3% | 49.4% | 55.8% |

Source: Table No. MJV-22, Panel C and Panel D.

### D. THE DCF COST OF CAPITAL ESTIMATES

**Q74. Did you estimate cost of equity using the DCF method for the two samples?**

A74. Yes, I estimate the cost of capital using the DCF method for the companies in both samples for which I have earnings growth rate forecasts.[39]

**Q75. What steps do you take in your DCF analyses?**

A75. Given the above discussion of DCF principles, the steps are to collect the data, estimate the sample companies' costs of equity at their current market value capital structures, and then to determine the deemed equity ratio consistent with the sample's estimated ATWACC and the 9.63 percent and 8.89 percent rates of return on equity.

#### 1. Growth Rates

**Q76. What growth rate information do you use?**

A76. For reasons discussed above and in Appendix C, historical growth rates today are not relevant as forecasts of current investor expectations for these samples. I therefore use forecasted rates.

The ideal in a DCF application would be a detailed forecast of future dividends, year by year well into the future until a true steady state (constant) dividend growth rate was reached, based on a large sample of investment analysts' expectations. I know of no

[39] I obtained growth rate forecasts for the Canadian sample from Globe and Mail's webpage (investdb.theglobeandmail.com.). The site does not report any forecasts for Gaz Métropolitain.

source of such data. Dividends are ultimately paid from earnings, however, and earnings forecasts from a number of analysts are available for a few years. Investors do not expect dividends to grow in lockstep with earnings, but for companies for which the DCF approach can be used reliably (*i.e.*, for relatively stable companies whose prices do not include the option-like values described in Appendix C), they do expect dividends to track earnings over the long-run. Thus, use of earnings growth rates as a proxy for expectations of dividend growth rates is a common practice.

Accordingly, the first step in my DCF analysis is to examine a sample of investment analysts' forecasted earnings growth rates from IBES and for companies in the U.S. sample forecasts from *Value Line*. The details are in Appendix C. At present, data run through a 2008-20010 horizon, which represents on average about a four and a half year forecast (from the 3rd quarter of 2005 to the end of 2009). The longest-horizon forecast growth rates from these sources underlie my simple DCF model (*i.e.*, the standard perpetual-growth model associated with the "DCF formula," dividend yield plus growth). Unfortunately, the longest growth forecast data only go out for a period of about five years, which is too short a period to make the DCF model completely reliable. I also use the five-year forecasts in conjunction with a forecast of the long-run GDP growth rate in a modest attempt at obtaining a multi-stage DCF estimate using company-specific growth rates.

**Q77. Do these growth rates correspond to the ideal you mentioned above?**

A77. No. While forecasted growth rates are the quantity required in principle, the forecasts need to go far enough out into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. As can be seen in Table No. MJV-5 for the Canadian sample and in Table No. MJV-16 for the U.S. gas LDC sample, the growth rates estimates do not support the view that investors are expecting growth rates equal to the single perpetual growth rate assumed in the simple DCF model. There are also generally fewer analysts forecasting earnings for the companies in the Canadian sample than for the gas LDC sample. The five-year growth rate forecasts vary from company to company, but the range for both samples is relatively narrow. The Canadian sample earnings growth forecasts are all 5 percent except for the 3 percent forecast for Canadian Utilities and the 7 percent forecast for Enbridge. The pattern is similar for the U.S. gas LDC sample whose forecasts vary from 4.2 to 6.2 percent except for the 8.5 percent forecast for Southwest Gas Company. For both samples the average forecast is roughly consistent with the forecast of long-term GDP growth of 4.3 percent for the Canadian sample and 5.5 percent for the gas LDC sample which suggests that optimism bias is not likely to be a major problem for these estimates.

In my opinion, a much longer detailed growth rate forecasts than currently available from IBES and *Value Line* would be needed to implement the DCF model in a completely reliable way for these two samples at this time; however, the general stability of the 5-year growth rate forecasts for both samples indicates a higher degree of reliability for the DCF model than has been true in the recent past.

### 2. Dividend and Price Inputs

**Q78. What values do you use for dividends and stock prices?**

A78. Dividends are for the 3rd quarter of 2005, the last recorded dividend payment reported by Compustat. This dividend is grown at the estimated growth rate and divided by the price described below to estimate the dividend yield for the simple DCF model.

Stock prices are an average of closing stock prices for the 15-day trading period ending January 3, 2006 for the Canadian utility sample and ending December 16, 2005 for the U.S. Gas LDC sample. These dates coincide with the release of the IBES growth forecasts for the samples.[40] A 15-day stock price average is used to guard against anomalous price changes in any single day.

### 3. DCF Estimates for the Canadian Utility Sample

**Q79. What are the DCF estimates for the samples?**

A79. The data are used in the two versions of the DCF method to get cost equity and ATWACC estimates using each sample company's market value capital structure. The

[40] The source for the Canadian IBES data does not list a specific release date for the earnings growth rate forecasts. The data were downloaded on January 3, 2006. Capital structure and dividend information is from Compustat which had data only up until September, 30, 2005 at the time of analysis.

DCF cost of equity estimates for each sample company are displayed in Panel A (simple DCF) and Panel B (multistage DCF) of Table No. MJV-6. The corresponding estimates of the ATWACC for each company is displayed in Panels A and B of Table No. MJV-7. The average ATWACC estimates for the full sample and subsample are shown at the bottom of the tables. The resulting deemed equity ratios at a 9.63 percent rate of return on equity are shown in Table No. MJV-8 and in Table 3 below along with the sample average ATWACC estimates. Panel A of Table 3 is for the full sample and Panel B is for the subsample. These results are very close to the Canadian sample's risk positioning results, but I do not believe that these results are completely reliable for the reasons discussed above.

**Table 3: Panel A**

**Canadian Regulated Utility Sample**
**Discounted Cash Flow After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for All Companies**

| Discounted Cash Flow Method | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63 %RoE) | (8.89% RoE) |
| Simple DCF Method (Quarterly) | 6.1% | 45.6% | 51.5% |
| Multi-Stage DCF Using the Long-Term GDP Forecast as the Perpetual Rate | 5.8% | 40.8% | 46.1% |

Source: Table No. MJV-8, Panel A and Panel B.

| Discounted Cash Flow Method | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | **(9.63% RoE)** | **(8.89% RoE)** |
| Simple DCF Method (Quarterly) | 6.2% | 47.7% | 53.9% |
| Multi-Stage DCF Using the Long-Term GDP Forecast as the Perpetual Rate | 5.9% | 42.8% | 48.4% |

**Table 3: Panel B**
**Canadian Regulated Utility Sample**
**Discounted Cash Flow After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for Companies with No Mergers or Dividend Cuts**

Source: Table No. MJV-8, Panel A and Panel B.

### 4. DCF Estimates for the Gas LDC Sample

**Q80. Is there any difference between U.S. gas LDC companies you rely upon for your risk positioning method and for your DCF method?**

A80. No.

**Q81. What DCF deemed equity estimates do you obtain for the sample?**

A81. The growth rate forecast used in the DCF method is the weighted average of the growth estimates from IBES and *Value Line*. The DCF cost of equity estimates for each company are in Panel A (simple DCF) and Panel B (multistage DCF) of Table No. MJV-17. The ATWACC estimates for each company and the sample averages are displayed in Panels A and B of Table No. MJV-18. The resulting deemed equity components for each sample average ATWACCs are shown in Table No. MJV-19 and in Table 4 below. Panel A is for the full sample and Panel B is for the subsample. The results for the DCF model for the gas LDC sample are uniformly higher than the DCF estimates for the Canadian utility sample and higher than the risk positioning estimates for either sample. Although I do not rely upon the DCF estimates, they suggest that the risk positioning estimates potentially underestimate the true cost of the sample companies at this time. This observation is consistent with the trend in the beta estimates in the figures above.

**Table 4: Panel A**

**U.S. Gas LDC Sample**
**Discounted Cash Flow After-Tax Weighted-Average Cost of Capital and Deemed Equity Estimates for All Companies**

| Discounted Cash Flow Method | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63% RoE) | (8.89% RoE) |
| Simple DCF (Quarterly) | 7.4% | 65.5% | 73.9% |
| Multi-Stage DCF Using the Long-Term GDP Forecast as the Perpetual Rate | 7.4% | 65.7% | 74.1% |

Source: Table No. MJV-19, Panel A and Panel B.

**Table 4: Panel B**

**U.S. Gas LDC Sample
Discounted Cash Flow After-Tax Weighted-Average Cost of Capital
and Deemed Equity Estimates for Companies with
Revenues from Regulated Activities of > 70 percent.**

| Discounted Cash Flow Method | ATWACC | Deemed Equity Percent | |
|---|---|---|---|
| | | (9.63% RoE) | (8.89% RoE) |
| Simple DCF (Quarterly) | 7.4% | 65.9% | 74.4% |
| Multi-Stage DCF Using the Long-Term GDP Forecast as the Perpetual Rate | 7.1% | 60.9% | 68.7% |

Source: Table No. MJV-19, Panel A and Panel B.

## E. THE SAMPLES' DEEMED EQUITY ESTIMATES

**Q82. What conclusions do you draw from the DCF analysis?**

A82. The estimated ATWACC and deemed equity components from both versions of the DCF model are only slightly higher than the estimates from the risk positioning model for the Canadian sample as well as the subsample, but the DCF results for the gas LDC samples are substantially higher than the risk positioning estimates for either sample. The simple DCF model estimates that relies on company-specific growth rate forecasts vary significantly among companies and are less reliable because the long-run growth rate forecast drives the results, and there are *no* objective data on the long-run growth rate investors truly expect, *nor* on when the industry is expected to settle down into some sort of stable-growth equilibrium. The ATWACC and cost of equity estimates that rely on the multistage DCF model are more reliable because the long-term growth rate used in the analysis is the forecast growth rate for the economy.

Although I do not rely upon the DCF model results, I believe that DCF cost capital estimates provide a useful check on the risk positioning results for both samples. The DCF results provide confidence that the results from the risk positioning model are reasonable, particularly for the Canadian sample, and the higher DCF results for the gas LDC sample suggest that the risk positioning estimates are probably downward biased for the U.S. sample and perhaps the Canadian sample, as well. This observation is consistent with the current difficulty with estimating beta.

**Q83. Do you have any preliminary comments regarding the results of the risk positioning models?**

A83. Yes. As shown above in Figures 3 and 4, betas measured in the standard way using 60 months of historical data have declined to values very near to zero. Ordinarily, using historical data to estimate beta is not a serious problem because the overall business risk of an industry probably does not change rapidly. For an industry undergoing major changes, however, the beta estimates based upon the historical data may not capture the full changes in risk in the industry. This is true even though information on the probability and provisions of industry changes have been available some months ago. The fall in the estimated betas for both the U.S. and the Canadian samples might seem to be an unexpected result because the introduction of more competition in the natural gas and electric industries increases risk. However, such "decoupling" of beta from the normal relationship to the market appears to be a common feature of industries undergoing structural changes. This factor also suggests that the risk positioning estimates may be downward biased and is consistent with the information from the DCF model for the gas LDC sample.

**Q84. What conclusions do you draw from the risk positioning results?**

A84. The risk positioning results are summarized above in Tables 1 and 2. Of those results, the CAPM values deserve the least weight, because this method does not adjust for the empirical finding that the cost of capital is less sensitive to beta than predicted by the CAPM (which my written evidence considers by using the ECAPM). Conversely, the ECAPM numbers deserve the most weight, because this method adjusts for the empirical findings.

Focusing on the middle ECAPM model ($\alpha = 1\%$), the results on Panel B of Table No. MJV-11 show a rate of return on equity for the full Canadian sample of 8.2 percent for both the full sample and the subsample for capital structures that average 53 and 55 percent equity respectively.[41] The deemed equity components displayed in Table 1, Panel A and Panel B are the average equity ratios the sample companies would have had if their estimated rate of return on equity had been 9.63 or 8.89 percent. Note that in this calculation the sample average ATWACC and the 9.63 percent (or 8.89 percent) rate of return on equity are held constant; only the deemed capital structures differ.

Panel B of Table No. MJV-21 shows the comparable estimates for the risk levels of the companies in the U.S. gas LDC sample applied to the Canadian capital market benchmarks. The cost of equity results range from 7.7 to 9.0 percent for capital structures that average about 58 percent equity. The U.S. sample has a slightly higher average ATWACC than the Canadian sample although the estimated costs of equity are similar. The result is that the deemed equity components displayed in Table 2 are about two percent higher than those for the Canadian sample displayed in Table 1.

**Q85. Please summarize the evidence on the deemed equity thickness that is consistent with the sample evidence at a 9.63 percent and the 8.89 percent returns on equity.**

A85. Relying primarily on the estimates the risk positioning model for the two subsamples, the point estimate of the deemed equity ratio for the Canadian sample is 44 percent equity and 46 percent equity for the gas LDC sample at a rate of return on equity of 9.63 percent. It is more correct, however, to say that the results indicate a range of values. The range

[41] Note that I dropped Emera from the risk positioning results because its estimate of the cost of equity is not greater than its market cost of debt plus 25 basis points. See Workpaper #1 to Table No. MJV-11.

is 40 to 48 percent equity thickness for the Canadian sample and 42 to 50 percent for the gas LDC sample. The comparable estimate for the 8.89 percent return on equity is 50 percent with a range of 46 to 54 percent equity for the Canadian sample and 52 percent with a range of 48 to 56 percent for the gas LDC sample. Although the gas LDC sample has a slightly higher ATWACC, the corresponding point estimate for both samples for the ATWACC is about 6 percent with a range of plus or minus ¼ percent around the midpoint or between 5¾ and 6¼ percent.

Note in estimating the sample ATWACC, I round to the nearest ¼ percent because I do not believe that cost of capital estimates can be made more precisely than that and because I give equal weight to each approach. This means that the estimated deemed equity ratios do not match precisely the estimates of the ATWACC because of differences due to rounding. As noted above, I estimate the deemed equity component to the nearest 4 percent which corresponds roughly to a ¼ percent change in the ATWACC.

**Q86. Does this conclude your written evidence?**

A86. Yes, it does.

## Appendix A: QUALIFICATIONS OF MICHAEL J. VILBERT

Michael Vilbert is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined *The Brattle Group* in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

## REPRESENTATIVE CONSULTING EXPERIENCE

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team which prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electrical power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has assisted in the preparation of testimony and the development of estimation models in numerous cost of capital cases for natural gas pipeline and electric utility clients before the FERC and state regulatory commissions. These have spanned standard estimation techniques (DCF, CAPM) and have also developed and applied more advanced models specific to the industries or lines of business in question, *e.g.*, based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated for major disallowances for QF contract management in its allowed cost of capital.

- Dr. Vilbert was a member of a team which analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the northeast, Dr. Vilbert analyzed the auction of an electric utilities purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the revenue requirement of the authority required estimation of the ratebase value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including an estimate of its cost of capital, and evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous products and shippers, improved cost analysis and evaluation of bottlenecks in the system.

- For a southeastern utility, Dr. Vilbert was part of a team quantifying the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the rate payers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of *The Brattle Group*, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the Province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecast remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of an petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

**PRESENTATIONS**

"Utility Distribution Cost of Capital" by Michael J. Vilbert, *EEI Electric Rates Advanced Course, Bloomington, IN*, 2002, 2003

"Issues for Cost of Capital Estimation," by Bente Villadsen and Michael J. Vilbert, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

"Not Your Father's Rate of Return Methodology" by Michael J. Vilbert, *Utility Commissioners/Wall Street Dialogue*, NY, May 2004

"Cost of Capital Estimation: Issues and Answers," MidAmerican Regulatory Finance Conference, Des Moines, IA, April 7, 2005.

"Cost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business," EEI Economic Regulation & Competition Analysts Meeting, May 2, 2005.

"Current Issues in Cost of Capital," by Michael J. Vilbert and Bente Villadsen, *EEE Electric Rates Advanced Course, Madison, WI*, 2005.

**ARTICLES**

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," prepared by Frank C. Graves and Michael J. Vilbert, white paper for Edison Electric Institute (EEI) to the IRS, July 25, 2003.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute*, April 2005.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

**TESTIMONY**

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, October 1998.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

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Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Written evidence, Rebuttal, Reply and further Reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, May 2001, Nov. 2001, Feb. 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001.

Direct testimony (with Bill Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002

Direct Testimony and Hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct Testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-___-000, March 2003.

WRITTEN EVIDENCE OF
MICHAEL J. VILBERT

Direct Report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-01-007, April 2003.

Direct and Rebuttal Report before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Proceeding No. 1271597, July 2003, November 2003

Written Evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N–7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, January 2004.

Direct and Rebuttal Testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004

Direct and Rebuttal Testimony before the Federal Energy Regulatory Commission, on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005

Direct Testimony before the Arizona Corporation Commission, Cost of Capital for Paradise Valley Water Company, a subsidiary of Arizona-American Water Company, Docket No. WS-01303A-05, May 2005.

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MICHAEL J. VILBERT

**Appendix B**

**EQUITY RISK PREMIUM APPROACH METHODOLOGY: EMPIRICAL RESULTS**

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MICHAEL J. VILBERT

**Appendix B**

# EQUITY RISK PREMIUM APPROACH METHODOLOGY: EMPIRICAL RESULTS

**Q1. What is the purpose of this appendix?**

A1. This appendix describes the estimation of the parameters used in the equity risk premium models, the sample selection procedures and the details of the cost of capital estimates obtained from this methodology.

## I. EMPIRICAL EQUITY RISK PREMIUM RESULTS

**Q2. How is this appendix organized?**

A2. This appendix presents the full details of my equity risk premium approach analyses, which are summarized in the body of my written evidence. It discusses the sample selection process used, and then the forecasts of the short-term and the long-term risk-free interest rates. Next it addresses the estimates of the MRP I use in the models. Finally, it reports the CAPM and ECAPM results for the samples' costs of equity and then describes the analysis of capital structure effects.

### A. PRELIMINARY MATTERS

#### 1. CANADIAN SAMPLE

**Q3. How do you select your Canadian sample companies?**

A3. The appropriate deemed equity thickness for Union Gas Limited's ("Union" or the "Company") regulatory rate base consistent with the OEB's formula-determined return on equity and the cost of capital estimates from the samples is the subject of my evidence. So, the goal of the sample selection process is to create a sample of companies whose primary business is as a regulated utility in Canada with business risk generally similar to that of the Company.

To construct this sample, I started with the universe of Canadian companies classified as being in the utility industry in the FPinfomart database.[1] There were a total of 46 companies classified as electric utilities, ten classified as gas utilities, six classified as "multi-utilities", one classified as "Independent Power Producers & Energy Traders" and eight classified as "Oil & Gas Storage & Transportation." I eliminated companies that were not listed in the FP500 Sales category on FPinfomart which eliminated a number of smaller companies. I then applied additional selection criteria designed to narrow the sample to companies with characteristics similar to that of Union. I also eliminated companies with unique circumstances which may bias the cost of capital estimates. The final sample is five companies (Canadian Utilities, Enbridge, TransCanada, Fortis, and Gaz Metro LP) for the risk positioning estimates, because Emera's estimated beta is only 0.06, and five companies (Canadian Utilities, Enbridge, TransCanada, Emera, and Fortis) for the DCF analysis, because I know of no source providing long-term earnings growth estimates for Gaz Metro LP. A beta of 0.06 is

[1] The information was extracted in January 2006 from www.fpinformart.ca.

equivalent to a risk-free asset and results in an estimate of the cost of equity for Emera that is less than its cost of debt, neither of which is a reasonable estimate of the cost of Emera's equity.

If I were to apply the same sample selection criteria to the Canadian sample as I apply to the U.S. gas LDC sample, some of the remaining companies would be eliminated. Fortis acquired significant assets in 2004,[2] and Gaz Metropolitain is a partnership rather than a corporation. I elected to include these companies in the sample because eliminating them would leave only four companies, but these two companies are not part of the four company (three for risk positioning) subsample (Canadian Utilities, Enbridge, Emera and TransCanada) with no recent mergers, acquisitions or special ownership structures. The subsample is selected to be as free of issues which may confound the estimation of the cost of capital as is possible within the universe of Canadian utilities. Unfortunately, I have some concerns even about the remaining companies. It is for these reasons as well as others that a second sample is essential, in my opinion, to estimating reliably the cost of capital for the Company.

Table No. MJV-2 reports the share of operating revenues from regulated activities for these companies for 2004, the most recent full year of data. (Table No. MJV-1 provides an index to the other tables.)

[2] Fortis's acquisition of Aquila assets, now called FortisAlberta, was announced in September, 2003 and completed in May 2004. Source: Fortis website. Terasen was acquired by Kinder Morgan on November 30, 2005 and is no longer part of the Canadian utility sample.

**Q4. What are the additional selection criteria you applied?**

A4. I eliminated all companies not traded on the Toronto Stock Exchange, companies with a high probability of financial distress and companies which cut their dividends during the period 2001 to today. Financial distress is measured by a Standard & Poor's ("S&P") debt rating of less than BBB- as reported by Compustat. BBB- is the lowest investment grade credit rating available from S&P.

I also screened for merger and acquisition activity, but I did not exclude companies with merger or acquisition activity from the full Canadian sample. Instead, I used it as a criteria for exclusion from the subsample. The screen for merger activity is any mention of merger activity on the company's web page.[3] I eliminated companies whose 2004 total revenues were less than $200 million to avoid problems associated with small companies such as thin trading and size effects. I required that the companies have data available from Compustat for the relevant period. Finally, I require that the companies' revenue from regulated activities be at least 70%.

**Q5. Why would you normally eliminate companies currently involved in a merger from your sample?**

A5. The stock prices of companies involved in mergers are often more affected by news relating to the merger than to movements in the stock market. In other words, the stock price "decouples" from its normal relationship to the stock market (the economy) which

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[3] The companies web pages were reviewed in November 2005.

is the basis upon which a company's cost of capital is calculated. Instead the stock price of a merger candidate is more affected by the latest speculation on the terms and probability of the merger. It is for this reason that Fortis is not included in the subsample.

**Q6. Were companies eliminated from the Canadian sample due to the magnitude of their annual revenues?**

A6. Yes, Algonquin Power Income Fund, Great Lakes Hydro Income Fund and Pacific Northern Gas LTD all had 2004 revenues below $200 million.

**Q7. What other companies were dropped from the Canadian sample?**

A7. Hydro-Quebec, Ontario Power Generation Inc., Hydro One Inc., Newfoundland Power Inc., BC Hydro and Power Authority, The Manitoba Hydro Electric Board, New Brunswick Power Corp, Saskatchewan Power Corp, Newfoundland and Labrador Hydro, and Heating Oil Partners Income Fund were eliminated because they are not listed on the Toronto Stock Exchange. Nova Scotia Power Inc. was eliminated for lack of five years of Compustat data, and because it is part of Emera which is included in the sample. Union Gas LTD and TransCanada Pipelines LTD were eliminated as they are affiliated with other companies and lack five years of Compustat data. Superior Plus Income Fund was eliminated due to its non-investment grade bond rating. Energy Savings Income Fund did not have five years of dividend information. Fort Chicago Energy Partners and Inter Pipeline Fund had dividend cuts. EPCOR Power LP is owned by TransCanada, ATCO LTD belongs to the same group as Canadian Utilities, and AltaGas Income Trust is owned by Enbridge. To avoid double counting these companies were eliminated. TransAlta was eliminated due to divestiture of its transmission assets.

**Q8. Were any other companies eliminated from the sample?**

A8. Yes. Pembina Income Fund was eliminated because it is an income fund rather than a corporation. Although there are a number of income funds among the initial companies considered, all other income funds were eliminated from the sample for other reasons.

**Q9. Why do you eliminate income funds from your sample?**

A9. Income funds are exempt for corporate income taxes provided they distribute most of their earnings, and they frequently distribute more than their earnings in a year in the form of a return of capital. These characteristics and others make income funds unsuitable as sample companies for regulated entities.

### 2. U.S. GAS LOCAL DISTRIBUTION COMPANY SAMPLE

**Q10. How do you select your gas local distribution company sample?**

A10. To select this sample, I started with the universe of publicly traded gas distribution utilities covered by *Value Line*. This resulted in an initial group of 16 companies.[4] I then eliminated companies by applying additional selection criteria designed to eliminate companies with unique circumstances which may bias the cost of capital estimates. The

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[4] The 16 companies are from *Value Line Investment Survey's* Standard Edition, reviewed December 16, 2005.

final sample consists eight gas local distribution ("gas LDC") companies. Table No. MJV-13 reports operating revenue shares from regulated activities for these companies for 2004.

**Q11. What are the selection criteria you applied?**

A11. I eliminated all companies whose regulated revenues are not greater than 50 percent of total revenues because one goal for this sample was for the sample companies to derive the majority of their revenues from regulated activities particularly in the natural gas distribution industry. I also eliminated all companies whose S&P bond rating as reported by Compustat was less than BBB- and companies that had a large merger during the period January 2001 to November 2005.[5] The screen for merger activity is any mention of merger activity in the analyst report section of *Value Line* or sizeable mergers found during a search of the companies' web pages.[6] To guard against measurement bias caused by "thin trading," I also restricted the sample to companies with total operating revenues greater than $300 million in 2004 and a market value in excess of $150 million as reported by *Value Line*.[7] Finally, I require that the companies have historical data available from Compustat for the relevant period.

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[5] For purposes of sample selection, a sizeable merger is defined to be one which would exceed 25 percent of the total capitalization of the company at the time of the merger announcement.

[6] Company web pages were searched in December 2003 for merger and acquisition activities during the 2001-2003 period and in November 2005 for merger and acquisition activities during the period 2004 through October 2005.

[7] As reported by *Value Line* on December 16, 2005.

**Q12. What companies were eliminated from the gas LDC sample because their share of revenue from distribution activities is not above 50 percent?**

A12. New Jersey Resources was eliminated from the sample because its revenue share from natural gas distribution is not above 50%. Additionally, the percentage of its income from marketing and other wholesale activities increased by 21 percent in 2004.[8]

**Q13. Were any other companies eliminated?**

A13. Yes. AGL Resources, Atmos Energy, Piedmont Natural Gas and Southern Union were eliminated for recent or current merger activities. Semco Energy was eliminated because Compustat reports that it has a non-investment grade credit rating. Nicor Inc. was eliminated from the sample because it restated earnings for 1999-2001 and because Nicor settled regulatory compliance issues with the Federal Energy Regulatory Commission ("FERC") in 2003.[9] UGI Corp. was eliminated because it primarily sells propane which is non-regulated.

**Q14. Are there any issues with remaining companies in your sample?**

A14. Perhaps. South Jersey Industries reported revenue from energy trading activities in its 10-Ks. Given the turmoil of the energy trading markets, the companies' cost of capital estimates may be more volatile than those of more stable companies. Additionally,

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[8] *Value Line* sheet for New Jersey Resources, December 16, 2005.

[9] Nicor announced on Oct. 29, 2002 that its earnings for 1999-2001 would be revised downwards by $15-35 million. March 4, 2003, Nicor released its restated earnings for 1999-2001 along with 2002 earnings.

KeySpan, Peoples Energy, South Jersey Industries and WGL Holdings have obtained on average less than 70 percent of their revenues from regulated activities in 2004.

Because this sample is designed to be as close to a "pure play" in the natural gas distribution industry as possible, I report results for a subsample (Cascade Natural Gas, Laclede Group, Northwest Natural Gas, and Southwest Gas) that consists of only those companies that have earned at least 70 percent of their revenue from regulated activities during 2004.

**Q15. Please compare the Canadian utility sample and the U.S. gas LDC sample.**

A15. For each sample, I summarize the characteristics of both the full sample and the subsample. The gas LDC subsample has higher percent of revenues from regulated activities than the full sample, while the companies in Canadian utility subsample are those companies with fewer data problems. In terms of percentage of revenues from regulated operations, the two samples are very similar. The companies in both the gas LDC sample and the Canadian utility sample earn a substantial percentage of their revenue from regulated activities. For the gas LDC sample, the average percentage of revenues from regulated activities is 80 percent in 2004 and this fraction increases to 96 percent for the subsample. For the Canadian utility sample, the average percentage of revenues from regulated activities in 2004 is 85 percent for both the full sample and for the subsample. (See Tables No. MJV-2 and No. MJV-13).

The U.S. gas LDC and Canadian utility samples differ primarily in the fact that the gas LDC sample is concentrated in one segment of the regulated natural gas industry while the Canadian sample consists of companies in the electric, gas and petroleum industries. All companies in the gas LDC sample are gas distribution companies regulated by one or more states. In comparison, the companies in the Canadian sample consists of three companies primarily in the electric industry (Canadian Utilities, Emera, and Fortis), one company primarily in the gas distribution industry (Gaz Metropolitan) and two pipeline companies (Enbridge and TransCanada). The subsample of the Canadian utilities consists of two electric utilities and two pipeline companies.

The regulatory risk of the two sample seems to be similar. Looking at the full U.S. gas LDC sample, all companies have a fuel adjustment clause that allows them to pass (at least part of) increases in gas purchase costs onto their customers. Among the companies in the Canadian utility sample, some appear to have formal fuel adjustment clauses while others do not discuss this in their annual reports. Most (if not all) Canadian utilities have deferral accounts that allow that to make up for many additional expenses (e.g., increases in fuel costs) incurred during a period. Some gas LDC companies have tariffs that contain provisions that permit the recovery of (some) environmental remediation costs. For example, KeySpan and South Jersey Industries have such provisions.[10] All gas LDC companies discuss environmental clean-up requirements, and one of the eight companies indicate in their 10-K reports that it might significantly and negatively affect their future performance.

[10] KeySpan 2004 10-K, p. 145 and South Jersey Industries 2004 10-K, p. 6. Neither company is included in the subsample.

**Q16. What do you conclude from the comparison of the Canadian utility and the U.S. gas LDC samples?**

A16. The two samples differ primarily in that the U.S. gas LDC sample operates essentially in only in the regulated natural gas distribution industry, while the companies in the Canadian sample operate in the electric, natural gas distribution, natural gas pipeline and petroleum pipeline industries. The samples are very similar in terms of the percentage of revenues from regulated operations. Compared to the Canadian utility sample, the gas LDC sample provides an excellent comparison sample for the Canadian regulated natural gas distribution industry but without the complications of substantial data issues and different industries that affects the Canadian sample.

**Q17. Do the companies in the U.S. gas LDC sample own storage and transmission facilities similar to those of Union?**

A17. Five of the eight sample companies own some storage and transmission facilities but on a much smaller scale than for Union. Please refer to the following table for a description of the storage and transmission facilities owned by the sample companies.

Table No. MJV-B1

**LDC Sample's Storage and Transmission Activities**

| | Offers Any Pipeline or Storage Services That Are Comparable to Union's? | Description |
|---|---|---|
| Cascade Natural Gas | No | |
| KeySpan Corp | Yes (storage and transportation), but on a smaller scale than Union | Owns a 20.4% interest in an interstate pipeline, Iroquois Gas Transmission, with capacity 1,200 TJ/d. Owns an interest in two interstate pipelines (50% of Islander East Pipeline Company, 21% of Millennium Pipeline) that are not yet on-line. Owns 52% of the Honeoye storage facility (with capacity 5,100 TJ) and 34% of a partnership which owns 50% of the Steuben storage facility (with capacity 6,500 TJ). |
| Laclede Gas Co | No | |
| Northwest Natural Gas | Yes (storage and transportation), but on a smaller scale than Union | Owns the Mist storage field (with capacity 13,600 TJ, 9,400 TJ of which is currently committed to NW Natural's core customers) and an associated pipeline that connects Mist with NW Natural's distribution system. Owns a 10% interest (representing less than 20 TJ/d) in the Kelso Beaver pipeline. |
| Peoples Energy Corp | Yes (storage and transportation), but on a smaller scale than Union | Owns a gas storage reservoir (Manlove Field). Owns a natural gas pipeline system that runs from Manlove Field to Chicago. Offers limited FERC jurisdictional storage and transportation services to third parties. |
| South Jersey Industries | No | |
| Southwest Gas | Yes (transportation), but on a smaller scale than Union | A subsidiary owns the Pauite pipeline (with capacity of less than 210 TJ/d). |
| WGL Holdings | Yes (storage), but on a smaller scale than Union | Owns the Hampshire underground storage facility (with capacity of 2,100 TJ) which provides storage services only to Washington Gas Light. |

Source: 2004 10-K pp.3-8; 2004 10-K pp.16-17; 2004 10-K pp. 4-8; 2004 10-K pp. 10-11, 94, Company website; 2004 10-K p.13, FERC Annual Transportation Reports and Semiannual Storage Reports; 2004 10-K pp. 3-12; 2004 10-K p. 2, Paiute Pipeline FERC Annual Capacity Filing; 2004 10-K p. 4, 21

## 3. OTHER PRELIMINARY MATTERS

**Q18. What capital structure information do you require?**

A18. For reasons discussed in my written evidence and explained in detail in *Section III* of Dr. Kolbe's written evidence, explicit evaluation of the market-value capital structures of the sample companies versus the capital structure used for rate making is vital for a correct interpretation of the market evidence. This requires estimates of the market values of common and preferred equity and debt, and the current market costs of preferred equity and debt.

**Q19. How do you calculate the market-value capital structures of the sample companies?**

A19. I estimate the capital structure for each company by estimating the market values of common equity, preferred equity and debt from publicly available data. The calculations are in Panels A to F of Tables No. MJV-3 for the Canadian Utility sample and Panels A to H of Table No. MJV-14 for U.S. gas LDC sample.

The market value of equity is straightforward: the price per share times the number of shares outstanding. The market value of preferred is set equal to its book value. The market value of debt is estimated at its book value for the sample of U.S. companies since the market value of debt generally does not differ materially from its book value at this time. For the Canadian sample, I calculate the market value of debt by discounting each company's embedded interest payments by the current yield of bonds having the same bond rating as the company assuming a ten-year average maturity.[11] If there are debt instruments with a floating rate interest rate or instruments for which no coupon rate is provided, I set the market value equal to the book value.

[11] The assumption of a ten year maturity is a simplification. Currently, the bonds with the highest embedded costs are also generally those issued furthest in the past. Bonds issued more recently have embedded costs which are closer to the current market rates of interest. The ten year maturity assumption is designed to capture the market value of the bonds with embedded costs different than market interest rates, but also recognizes that the oldest bonds are also those likely to be repaid sooner.

For purposes of assessing financial risk to common shareholders, I add an adjustment for short-term debt to the debt portion of the capital structure. This adjustment is used only for those companies whose short-term (current) liabilities exceed their short-term (current) assets. I add an amount equal to the minimum of the difference between short-term liabilities and short-term assets or the amount of short-term. The reason for this adjustment is to recognize that when current liabilities exceed current assets, a portion of the companies long-term assets are being financed, in effect, by short-term debt.

Table No. MJV-3 (Canadian sample) reports the market value capital structure for the end of year 2004 and as of January 2006. Table No. MJV-14 (gas LDC sample) reports such calculations using the values at year end for the years ending 2000 - 2004 and values as of December 2005. The output of these tables is the market debt-to-value and preferred equity-to-value ratios. The overall cost of capital calculation for the gas LDC risk positioning estimates rely on the average of the market value capital structure computed for the years 2000 through 2004 and as of September 30, 2005 as shown in Table No. MJV-15. In the calculation, the year end results for the years 2001 through 2004 are weighted by one each while the 2000 year-end and the September 30, 2005 results are weighted by ¼ and ¾, respectively. The results in columns 1-3 are used to calculate the DCF capital structure, while columns 4-6 are for the risk positioning models. For the Canadian sample, the capital structure is the average of the capital structures over the last 52 weeks as shown in Table No. MJV-4 which is the period over which the betas estimates for the Canadian sample are based.

**Q20. How do you estimate the current market cost of preferred equity?**

A20. There is to my knowledge no public source for yields on preferred equity in Canada.[12] Therefore, the cost of preferred equity is set equal to the cost of debt on bonds of a comparable rating to the company's bond rating. Because the average amount of preferred equity in the capital structures of the Canadian sample companies is two to four percent and about zero for the gas LDC sample companies, this approximation will have a minimal impact.[13]

**Q21. How do you estimate the current market cost of debt?**

A21. I use the current yields on comparably rated bonds. Ideally, the cost of debt for each company in the DCF analysis would the be the current yield reported by an appropriate bond rating service on comparably rated bonds. For the risk positioning method, the appropriate cost would be the current yield corresponding to the period over which the company's beta was estimated (five-year average debt rating for the U.S. gas LDC sample and 52-weeks average for the Canadian utility sample) for each company. Because I only have access to current ratings from Dominion Bond Ratings Service, I rely on the current rating for the companies in the Canadian Utility sample.

The S&P debt ratings were obtained from Compustat when available for the U.S. gas LDC sample and the Dominion Bond Rating Service for the Canadian sample. When

[12] There are publicly available sources for preferred yields in the U.S. but throughout my analysis I use Canadian benchmarks.

[13] Union Gas has 3.2 percent (tax deductible) preferred securities in its regulatory capital structure.

Compustat did not report a rating for a single quarter, the rating was assumed equal to the prior or next quarter.[14]

Based on the CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005, the December 2005 long-term bond yield for A-rated and BBB-rated utility companies was 4.90 percent and 5.31 percent, respectively.[15,16]

For the firms in the gas LDC sample, the bond rating for each company is used with the yield data on Canadian bonds of an equivalent rating.[17] Calculation of the after-tax cost of debt uses the Company's estimated marginal income tax rate for 2005 of 36.1 percent.[18]

## B. RISK-FREE INTEREST RATE FORECAST

**Q22. How do you obtain the forecasts of the risk-free interest rate?**

A22. I rely on interest rate forecasts from Consensus Economics Inc., a London based forecast survey firm which provides forecasts of interest rates, inflation rates and other economic indicators for many countries world wide. In particular, I use the January 9, 2006

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[14] Moody's rating for South Jersey Gas was used for South Jersey Industries.

[15] All companies in both samples are either BBB or A rated except one which is AA-rated. I calculated the yield on AA-rated utility bonds as the yield on A-rated utility bonds minus ½ times the spread between the yield on BBB and A rated utility bonds.

[16] CIBC World Markets reports only A and BBB rated average long-term yield, so I treat a rating of A- as A, and ratings of BBB+ and BBB- as BBB.

[17] Because a BBB rating is viewed differently in Canada than in the U.S., I estimate the yield on BBB rated utility bonds as 4.90 percent plus 30 basis points for the U.S. gas LDC sample companies.

[18] The tax rate is calculated as the sum of the Federal tax rate of 22.12% and the provincial tax rate of 14.0%.

*Consensus Forecasts* which forecasts a 4.60 percent yield for the 10-year Canadian Government bonds for the year ending January 2007.[19]

I add a maturity risk premium of 20 basis points to the 10-year bond yield forecast to adjust the forecast to the average maturity of the long-term bond yields used to estimate the long-term MRP. The bond maturity premium represents the extra return investors demand for tying up their money for longer periods. The addition of the maturity premium is necessary for consistency so that the average bond maturities in the data used to estimate the long-term market risk premium correspond to the maturity of the benchmark for the long-term risk free rate.[20] The addition of the maturity premium converts the yield forecast to an yield for a bond with a 15 to 18 year maturity.

**Q23. What value do you use for the long-term risk-free interest rate in the risk positioning models?**

A23. I use a value of 4.80 percent for the long-term risk-free interest rate as the benchmark interest rates in the equity risk premium analyses.

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19 See *Consensus Forecasts*, Survey Date, January 9, 2006 published by Consensus Economics, Inc.

20 The 20 basis point addition is a conservative estimate of the premium that investors require to hold bonds with a maturity of 15-18 years instead of bonds with a maturity of 10 years. The estimate is derived from a yield curve constructed from the historical average maturity premiums of Canadian Government bonds from 1951 through 2004 for bonds with five different average maturities (See Workpaper #2 to Table No. MJV-9).

## C. MARKET RISK PREMIUM ESTIMATION

**Q24. Please review the evidence on the historical market risk premium in Canada?**

A24. I consider evidence on three different measures of the historical MRP. The first is for use with the short-term risk free rate, and the other two measures are based upon the returns on long-term government bonds. The short-term measure is the average return on the market minus the average total return on 3-month Treasury bills. The second measure uses the total return on long-term Government bonds while the third uses the yield on long-term government bonds. The data are from the Report on Canadian Statistics 1924-2004. (See Workpaper #1 to Table No. MJV-9) From 1936 to 2004, the full period for which long-term Government bond total returns are reported, the data show that the average premium of stocks over three-month Government bills is 6.3 percent. I also examine the "post-War" period. The risk premium for 1948-2004 is 6.3 percent. (I exclude 1946 and 1947 because their economic statistics appear to be heavily influenced by the War years. They are not really "post-War" years, from an economic viewpoint.) The average risk premium is even higher at 6.8 percent if the full period of data, 1934-2004, for the short-term rate is used.[21] Subtracting the average maturity premium of about one percent for long-term bond yields over Treasury bill yields gives an estimate of 5.3 to 5.8 percent for the MRP over long-term bonds.[22] The average realized premium

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[21] Historical data on Government bond yields are not available until 1936 although information on 3-month Treasury bills is available in 1934. Total return on long-term Government bonds extends from 1924.

[22] Recall that the maturity premium is the difference in yield for bonds of longer maturity over those with (continued...)

over long-term Government bond yields is 5.2 percent for the full period 1934 to 2004, 4.9 percent for the 1936 to 2004 period and 5.4 percent for the post-war period, 1948 to 2004. The average premium over the total return on long-term Government bonds is 5.2% for the period 1924 to 2004, the longest period available.[23]

**Q25. Is this the only evidence you use to determine the "long-run realized risk premium" in Canada?**

A25. No. As discussed in my written evidence, I also consider scholarly articles on the MRP, estimates of the long-run realized risk premium in the U.S. and the results of the "International Cost of Capital" models discussed in Ibbotson Associates *SBBI Valuation Edition 2005 Yearbook*.[24]

**Q26. What is the "long-run realized risk premium"in the U.S.?**

A26. From 1926 to 2004, the full period reported, Ibbotson Associates data show that the average premium of stocks over Treasury bills is 8.6 percent. I also examine the "post-War" period. The risk premium for 1947-2004 is 8.5 percent. (I exclude 1946 because its economic statistics are heavily influenced by the War years; *e.g.*, the end of price controls yielded an inflation rate of 18 percent. It is not really a "post-War" year,

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22 (...continued)
shorter maturity.

23 The Canadian Government bonds used to estimate the long-term market risk premium represents bonds having an average maturity of 18 years.

24 See *SBBI: Valuation Edition 2005 Yearbook*, pp. 171-180.

from an economic viewpoint.) These averages often change slightly when another year of data is added to the Ibbotson series. However, as discussed above, there has been a great deal of academic research on the MRP done recently. This research has put practitioners in a dilemma: there is nothing close to a consensus about how the MRP should be estimated, but a general agreement in the academic community seems to be emerging that the old approach of using the average realized return over long periods gives too high an answer.

For the MRP over the long-term risk-free rate, the Ibbotson Associates data show that the average maturity premium of government bond yields over one month Treasury bills is about 1.5 percent. This suggests that stocks of average risk have commanded a premium of about 7.0 percent over the long-term risk-free rate and a market risk premium of 8.5 percent over the short-term risk-free rate in the U.S.

**Q27. How do you use these estimates of the U.S. MRP to help determine the appropriate Canadian MRP?**

A27. The increasing integration of the Canadian capital markets with those in the U.S., which is generally considered to have a higher MRP than Canadian markets, is likely to result in a narrowing of the difference in MRP, resulting in a slight increase in the Canadian MRP. Any estimate of the MRP for Canada must therefore consider the size of the MRP in United States as an important factor in determining the MRP for Canada.

**Q28. Given all of the evidence, what is your conclusion on the MRP in Canada?**

A28. It is clear that market return information is volatile and difficult to interpret, but my judgment is that the best available evidence on the MRP in Canada is that it lies in the range of 5.0 to 5.5 percent relative to the long-term risk free rate. This is consistent with a recent study of the MRP for 16 countries using data from more than 100 years (1900 to 2001) by Profs. Dimson, Marsh, and Staunton who report a 5.5 percent arithmetic mean excess return for Canada, over both the long-term and short-term risk-free rate.[25] The realized historical risk premiums varies, but the evidence from U.S. market data, scholarly articles and the models referenced in the Ibbotson Yearbook together lead to the conclusion that the MRP is likely to be at the upper end of the range so that 5.25 percent is a reasonable (and conservative) estimate of the risk premium over long-term bonds in Canada. This is 25 basis point lower than I used in my last written evidence before the NEB in RH-2-2004.

## D. COST OF CAPITAL ESTIMATES

**Q29. Based on these data, what cost of equity values do you calculate for the Canadian sample companies?**

A29. Table No. MJV-10 presents the cost of equity results for the three versions of the equity risk positioning method using the long-term risk-free rate and values of $\alpha$ of one and two percent. Note that because of the difficulty with estimating the betas of the companies

[25] See Table 1 of Dimson, E., R. Marsh, and M. Staunton (2003), "Global Evidence on the Equity Risk Premium," *Journal of Applied Corporate Finance*, Volume 15, No. 4, pp. 27-38.

in the Canadian sample, I do not estimate a cost of equity for each company. Instead, I estimate an average beta for the full sample and one for the subsample. I, therefore, estimate a cost of equity corresponding to the average beta for the sample and subsample.

**Q30. How do you use the cost of equity results to estimate the companies' overall cost of capital?**

A30. The cost of equity results are combined with the sample (or subsample) average market value capital structure information, the cost of debt and preferred and the Company's tax rate to estimate the after-tax weighted average cost of capital. These calculations are displayed in Table No. MJV-11, Panels A - C. Panel A reports the results using the cost of equity estimated by the CAPM, while Panels B and C report the results for the ECAPM parameter $\alpha$ equal to one and two percent, respectively. In each panel, column eight reports the overall cost of capital for the full sample and the subsample.

**Q31. What do the estimates of the ATWACC imply about the deemed equity ratio at a 9.63 or 8.89 percent return on equity?**

A31. The sample average ATWACC from each panel of Table No. MJV-11 is reproduced in column one of Table No. MJV-12 which reports the deemed equity ratio consistent with each of the sample's average risk positioning ATWACC estimates. Panel A of Table No. MJV-12 reports the results for all sample companies. Panel B reports the results for sample companies with no recent mergers, acquisitions, or dividend cuts. This sample is also characterized by excluding partnership structures.

To guard against the results being biased by a few companies' unusual circumstances, the averages reported are computed using only those companies whose cost of equity is larger than their cost of debt plus 25 basis points. This is a common sense measure that recognizes that a company's equity is riskier than its debt. Any estimate of the cost of equity that does not exceed the cost of the company's own debt plus 25 basis points fails this common sense notion. The practical effect of this restriction was to exclude Emera from the risk positioning analyses because its estimated beta was only 0.06. The sample average ATWACCs and corresponding deemed equity ratios at a 9.63 and a 8.89 percent rate of return on equity are displayed in Table 1, Panels A and B of my written evidence.

**Q32. What cost of equity values do you calculate for the U.S. gas LDC sample?**

A32. The cost of equity estimates for the U.S. gas LDC sample are displayed in Table No. MJV-20 using the long-term risk-free rate and values of the ECAPM parameter $\alpha$ of one and two percent.

**Q33. How do you use the cost of equity results to estimate the companies' overall cost of capital?**

A33. Unlike the Canadian sample, the cost of equity results are combined with the *each* company's market value capital structure information, the cost of debt and preferred and the Company's tax rate to estimate the after-tax weighted average cost of capital. These calculations are displayed in Table No. MJV-21, Panels A - C. Panel A reports the results using the cost of equity estimated by the CAPM, while Panels B and C report the results for the ECAPM parameter $\alpha$ equal to one and two percent, respectively. In each panel, column eight reports the overall cost of capital for each company. The last row of each panel report the sample averages for the U.S. gas LDC sample and subsample.

**Q34. What do the estimates of the ATWACC imply about the deemed equity ratio at a 9.63 and 8.89 percent return on equity?**

A34. The sample average ATWACC from each panel of Table No. MJV-21 is reproduced in column one of Table No. MJV-22 which then calculates the deemed equity ratio consistent with each of the risk positioning estimates. The different panels in Table No. MJV-22 report the deemed equity ratio for the full sample and for the subsample of companies. Panel A reports the results for all sample companies. Panel B reports the averages for the subsample of companies that have a large percentage of revenues from regulated activities. The sample average ATWACCs and corresponding deemed equity ratios at a 9.63 and a 8.89 percent rate of return on equity are displayed in Table 2, Panels A and B of my written evidence.

**Q35. What do these values imply for the deemed equity ratio for Union Gas Limited?**

A35. I discuss the implications of the equity risk positioning results in the main body of my written evidence.

**Q36. Does this complete Appendix B?**

A36. Yes, except for the Table MJV-B2 which provides the academic references upon which I rely to estimate the value of the $\alpha$ parameter for use in the Empirical Capital Asset Pricing Model.

Table No. MJV-B2

| **Empirical Evidence on the Alpha Factor in ECAPM**[*)] | | |
|---|---|---|
| Author | Alpha Estimate | Period relied upon |
| Black (1993)[1)] | 1% for betas between zero and 0.80 | 1931-1991 |
| Black, Jensen and Scholes (1972)[2)] | 4.31% | 1931-1965 |
| Fama and McBeth (1972) | 5.76% | 1935-1968 |
| Fama and French (1992)[3)] | 7.32% | 1941-1990 |
| Litzenberger and Ramaswamy (1979)[4)] | 5.32% | 1936-1977 |
| Litzenberger, Ramaswamy and Sosin (1980) | 1.63% to 3.91% | 1926-1978 |
| Pettengill, Sundaram and Mathur (1995)[5)] | 4.6% | 1936-1990 |

*) The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique (unbiased, efficient, consistent). Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

1) Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.

2) Black, Jensen and Scholes estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.

3) Calculated using Ibbotson's data for the 30-day treasury yield.

4) Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax estimation results estimate alpha at 4.4%.

5) Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 to estimate the alpha parameter and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

**Sources:**

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WRITTEN EVIDENCE OF
MICHAEL J. VILBERT

**Appendix C**

# DISCOUNTED CASH FLOW METHODOLOGY: DETAILED PRINCIPLES AND RESULTS

TABLE OF CONTENTS

WRITTEN EVIDENCE OF
MICHAEL J. VILBERT

**Appendix C**

**DISCOUNTED CASH FLOW METHODOLOGY:
DETAILED PRINCIPLES AND RESULTS**

**Q1. What is the purpose of this appendix?**

A1. This appendix reviews the principles behind the discounted cash flow or "DCF" methodology and the details of the cost of capital estimates obtained from this methodology.

# I. DISCOUNTED CASH FLOW METHODOLOGY PRINCIPLES

**Q2. How is this section of the appendix organized?**

A2. The first part discusses the general principles that underlie the DCF approach. The second portion describes the strengths and weaknesses of the DCF model and why it is generally less reliable for estimating the cost of capital for the sample companies at the present time than the risk positioning method discussed in Appendix B.

## A. SIMPLE AND MULTI-STAGE DISCOUNTED CASH FLOW MODELS

**Q3. Please summarize the DCF model.**

A3. The DCF model takes the first approach to cost of capital estimation discussed with Figure 1 in Section II-A of my written evidence. That is, it attempts to measure the cost of equity in one step. The method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_T}{(1+k)^T} \qquad \text{(C-1)}$$

where "$P$" is the market price of the stock; "$D_i$" is the dividend cash flow expected at the end of period $i$; "$k$" is the cost of capital; and "$T$" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Most DCF applications go even further, and make very strong (*i.e.*, unrealistic) assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, the market price of the stock will be given by a very simple formula,

$$P = \frac{D_1}{(k-g)} \qquad \text{(C-2)}$$

where "$D_1$" is the dividend expected at the end of the first period, "$g$" is the perpetual growth rate, and "$P$" and "$k$" are the market price and the cost of capital, as before. Equation C-2 is a simplified version of Equation C-1 that can be solved to yield the well known "DCF formula" for the cost of capital:

$$k = \frac{D_1}{P} + g = \frac{D_0 x (1+g)}{P} + g \qquad \text{(C-3)}$$

where "$D_0$" is the current dividend, which investors expect to increase at rate $g$ by the end of the next period, and the other symbols are defined as before. Equation C-3 says that if Equation C-2 holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the simple DCF model. Of course, the "simple" model is simple because it relies on very strong (*i.e.*, very unrealistic) assumptions.

**Q4. Are there other versions of the DCF models besides the "simple" one?**

A4. Yes. If Equation C-2 does not hold, sometimes other variations of the general present value formula, Equation C-1, can be used to solve for $k$ in ways that differ from Equation C-3. For example, if there is reason to believe that investors do *not* expect a steady growth rate forever, but rather have different growth rate forecasts in the near term (e.g., over the next five or ten years), these forecasts can be used to specify the early dividends in Equation C-1. Once the near-term dividends are specified, Equation C-2 can be used to specify the share price value at the end of the near-term (e.g., at the end of five or ten years), and the resulting cash flow stream can be solved for the cost of capital using Equation C-1.

More formally, the "multi-stage" DCF approach solves the following equation for k:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_T + P_{TERM}}{(1+k)^T} \quad . \tag{C-4}$$

The terminal price, $P_{TERM}$ is estimated as

$$P_{TERM} = \frac{D_{T+1}}{(k - g_{LR})} \tag{C-5}$$

where $T$ is the last of the periods in which a near term dividend forecast is made and $g_{LR}$ is the long-run growth rate. Thus, Equation C-4 defers adoption of the very strong perpetual growth assumptions that underlie Equation C-2 — and hence the simple DCF formula, Equation C-3 — for as long as possible, and instead relies on near term knowledge to improve the estimate of $k$. I examine both simple and multi-stage DCF results below.

**Q5. What are the merits of the DCF model?**

A5. The DCF approach is conceptually sound if its assumptions are met but can run into difficulty in practice because those assumptions are so strong, and hence so unlikely to correspond to reality. Two conditions are well-known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: the variant of the present value formula, Equation C-1, that is used must actually match the variations in investor expectations for the dividend growth path; and the growth rate(s) used in that formula must match current investor expectations. Less frequently noted conditions may also create problems.

The DCF model assumes that investors expect the cost of capital to be the same in all future years. Investors may not expect the cost of capital to be the same, which can bias the DCF estimate of the cost of capital in either direction.

The DCF model only works for companies for which the standard present value formula works. The standard formula does *not* work for companies that operate in industries or markets options (*e.g.*, puts and calls on common stocks), and so it will not work for companies whose stocks behave as options do. Option-pricing effects will be important for companies in financial distress, for example, which implies the DCF model will *understate* their cost of capital, all else equal.

In recent years even the most basic DCF assumption, that the market price of a stock in the absence of growth options is given by the standard present value formula (*i.e.*, by Equation C-1 above), has been called into question by a literature on market volatility. In any case, it is still too early to throw out the standard formula, if for no other reasons than that the evidence is still controversial and no one has offered a good replacement. But the evidence suggests that it must be viewed with more caution than financial analysts have traditionally applied. Simple models of stock prices may not be consistent with the available evidence on stock market volatility.

**Q6. Normally DCF debates center on the right growth rate. What principles underlie that choice?**

A6. Finding the right growth rate(s) is indeed the usual "hard part" of a DCF application. The original approach to estimation of $g$ relied on average historical growth rates in observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates *g* as the average book rate of return times the fraction of earnings retained within the firm. But it is highly unlikely that historical averages over periods with widely varying rates of inflation, interest rates and costs of capital, such as in the relatively recent past, will equal current growth rate expectations.

A better approach is to use the growth rates currently expected by investment analysts, if an adequate sample of such rates is available. If this approach is feasible and if the person estimating the cost of capital is able to select the appropriate version of the DCF formula, the DCF method should yield a reasonable estimate of the cost of capital for companies not in financial distress and without material option-pricing effects (always subject to recent concerns about the applicability of the basic present value formula to stock prices as well as issues of optimism bias). However, for the DCF approach to work, the basic stable-growth assumption must become reasonable and the underlying stable-growth rate must become determinable *within the period for which forecasts are available*.

**Q7. What is the so called "optimism bias" in the earnings growth rate forecasts of security analysts and what is its effect on the DCF analysis?**

A7. Optimism bias is related to the observed tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. This tendency to over estimate growth rates is perhaps related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts, the cost of capital estimates from the DCF model would be too high.

**Q8. Does optimism bias mean that the DCF estimates are completely unreliable?**

A8. No. The effect of optimism bias is least likely to affect DCF estimates for large, rate regulated companies in relatively stable segments of an industry. Furthermore, the magnitude of the optimism bias (if any) for regulated companies is not clear. This issue is addressed in a paper by Chan, Karceski, and Lakonishok (2003)[1] who sort companies on the basis of the size of the IBES forecasts to test the level of optimism bias. Utilities constitute 25 percent of the companies in lowest quintile, and by one measure the level of optimism bias is 4 percent. However, the 4 percent figure does not represent the complete characterization of the results in the paper. Table IX of the paper shows that the median IBES forecast for the first (lowest) quintile averages 6.0 percent. The realized "Income before Extraordinary Items" is 2.0 percent (implying a four percent upward bias in IBES forecasts), but the "Portfolio Income before Extraordinary Items" is 8.0 percent (implying a two percent downward bias in IBES forecasts).

The difference between the "Income before Extraordinary Items" and "Portfolio Income before Extraordinary Items" is whether individual firms or a portfolio are used in estimating the realized returns. The first is a simple average of all firms in the quintile while the second is a market value weighted-average. Although both measures of bias

[1] L. K.C. Chan, J. Karceski, and J. Lakonishok, 2003, "The Level and Persistence of Growth Rates," *Journal of Finance* 58(2):643-684.

have their own drawbacks according to the authors,[2] the Portfolio Income measure gives more weight to the larger firms in the quintile such as regulated utilities. In addition, the paper demonstrates that "analysts' forecasts as well as investors' valuations reflect a wide-spread belief in the investment community that many firms can achieve streaks of high growth in earnings."[3] Therefore, it is not clear how severe the problem of optimism bias may be for regulated utilities or even whether there is a problem at all.

Finally, the two-stage DCF model also adjusts for any over optimistic (or pessimistic) growth rate forecasts by substituting the long-term GDP growth rate for the 5-year growth rate forecasts of the analysts in the years after year 5.

## B. CONCLUSIONS ABOUT DCF

**Q9. Please sum up the implications of this part of the appendix.**

A9. The unavoidable questions about the DCF model's strong assumptions — whether the basic present value formula works for stocks, whether option pricing effects are important for the company, whether the right variant of the basic formula has been found, and whether the true growth rate expectations have been identified — cause me to view the DCF method as *inherently* less reliable than equity risk premium approach, the other approach I use. However, because the DCF method has been widely used in the past and in other forums when the industry's economic conditions were different from today's, I

[2] Chan, Karceski, and Lakonishok, *op. cit.*, p. 675.

[3] Chan, Karceski, and Lakonishok, *op. cit.*, p. 663.

submit DCF evidence in this case. DCF estimates also serve as a check on the values provided by the risk positioning approach methods.

## II. EMPIRICAL DCF RESULTS

**Q10. How is this part of the appendix organized?**

A10. This section presents the details of my DCF analyses, which are summarized in my written evidence. The first part describes some preliminary matters, such as sample selection, calculation of sample capital structures, and so on. Then it turns to the details of the DCF estimates themselves.

In particular, implementation of the simple DCF models described above requires an estimate of the current price, the dividend, and near-term and long-run growth rate forecasts. The simple DCF model relies only on a single growth rate forecast, while the multi-stage DCF model employs both near-term individual company forecasts and long-run GDP growth rate forecasts. The remaining parts of this section describe each of these inputs in turn.

### A. PRELIMINARY MATTERS

**Q11. In the Appendix B discussion of "preliminary matters," you discuss sample selection and the capital structure/cost of capital data you need to complete your Equity Risk Premium analyses. What, if anything, is different when you use the DCF method?**

A11. First, the sample companies to which the DCF approach is applied differ slightly for the Canadian utility sample. To my knowledge Globe Investor does not report growth rates for Gaz Métropolitain, so no DCF analyses could be performed for that company. Fortis Inc. acquired Acquila Networks Canada in May 2004.[4] Terasen was acquired by Kinder Morgan on November 30, 2005 and is no longer a member of the sample.[5] As discussed in Section II.A.1 of Appendix B, companies involved in a recent merger or acquisition would normally be excluded from the sample because of the effect that mergers and acquisitions have on a company's stock price independent of market returns as well as the possible effect on earnings forecasts. Because of concerns about the small sample size from excluding these companies, I include Fortis in the full sample for the DCF estimates, but it is not included in the subsample.

Note that the timing of the market value capital structure calculations is different in the DCF method and in the equity risk premium method. The equity risk premium method relies on the average capital structure over the period used to estimate beta while the DCF approach uses only current data, so the relevant market value capital structure measure is the most recent that can be calculated. This capital structure is reported in columns 1-3 of Tables No. MJV-4 for the Canadian utility sample and in Table No. MJV-15 for the U.S. gas LDC sample.

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4 Fortis's acquisition of Aquila assets was announced in September, 2003 and completed in May 2004.

5 Source: www.terasen.ca

## B. GROWTH RATES

**Q12. What growth rates do you use?**

A12. For reasons discussed above, historical growth rates today are generally useless as forecasts of current investor expectations for the natural gas distribution industry. I therefore use rates forecasted by security analysts.

The ideal in a DCF application would be a detailed forecast of future dividends, year by year well into the future, based on a large sample of investment analysts' expectations. I know of no source of such data. Dividends are ultimately paid from earnings, however, and earnings forecasts are available for a few years. Investors do not expect dividends to grow in lockstep with earnings, but for companies for which the DCF approach can be used reliably (*i.e.*, for relatively stable companies whose prices do not include the option-like values described previously), they do expect dividends to track earnings over the long-run. Thus, use of earnings growth rates as a proxy for expectations of dividend growth rates is a common practice.

Accordingly, the first step in my DCF analysis is to examine a sample of investment analysts' forecasted earnings growth rates. For the U.S. sample, I utilize IBES and *Value Line's* forecasted earnings growth while Globe Investor provides growth forecasts for the Canadian utility sample companies. The projected earnings growth rates for the companies in the Canadian utility sample are in Table No. MJV-5 and for the U.S. gas LDC sample in Table No. MJV-16. Column [1] of Table No. MJV-5 reports analysts' forecasts of the long-term earnings growth for the Canadian utility companies while column [2] reports the number of analysts that provided a forecast. In Table No. MJV-16 columns [1] and [5] report the forecasted long-term growth rate using IBES and *Value Line*, respectively. Column [2] reports the number of analysts providing an IBES forecast, and column [6] reports the average of the IBES and *Value Line* five-year forecasts. (I treat the *Value Line* forecasts as though they overlap exactly with the forecasts from IBES.) These growth rates underlie my simple and multi-stage DCF analyses.

In particular, the five-year average annual growth rate is the perpetual growth rate I employ in the simple DCF model.[6] In the multi-stage model, I rely on the company-specific growth rate until 2010 and on the long-term GDP forecast for year 2015 onwards. During the years from 2010 to 2015 I assume the growth rate converges linearly towards the long-term GDP forecast.[7]

**Q13. Do these growth rates correspond to the ideal you mentioned above?**

A13. No, not completely. While forecasted growth rates are the quantity required in principle, the forecasts need to go far enough out into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. As can be seen in Table No. MJV-5 for the Canadian sample and in Table No. MJV-16 for the U.S. gas LDC sample, the

[6] This growth rate is in Table No. MJV-5 column 1 for the Canadian utility sample and in Table No. MJV-16 column 6 for the U.S. gas LDC sample.

[7] For Canada, I use a long-term GDP growth estimate obtained from the International Energy Outlook 2005. Because this growth estimate is in real terms, I combine the estimate with a long-term inflation estimate from Consensus Forecast, January 2006. For companies in the U.S. gas LDC sample, I use the long-term U.S. GDP growth estimate from Blue Chip Economic Indicators, October 10, 2005.

growth rates estimates do not support the view that investors are expecting growth rates equal to the single perpetual growth rate assumed in the simple DCF model. However, the 5-year growth rate estimates for the Canadian utility companies are relatively homogeneous as can be seen by reference to Table No. MJV-5. The forecasts for the companies in the Canadian sample range from 3 to 7 percent which is generally consistent with the 4.3 percent forecast for the long-term growth rate in Canadian GDP. However, only TransCanada (three analysts) and Enbridge (four analysts) have more than one analyst providing a forecast. For the U.S. gas LDC sample, all except one of the long-term growth rates is in the range from 4.2 to 5.9 percent, consistent with the long-term 5.5 percent GDP growth rate forecast for the U.S. One company (Southwest Gas) has an estimate of 8.5 percent. Every company in the gas LDC sample has at least 2 analysts providing growth rate estimates. (See Table No. MJV-16) The comparison between the growth rate forecasts and the growth in GDP indicate that these growth rate forecasts are not overly optimistic for either sample.

**Q14. How well are the conditions needed for DCF reliability met at present?**

A14. The requisite conditions for the sample companies are not fully met at this time. Of particular concern for this proceeding is the uncertainty about what investors truly expect the long-run outlook for the sample companies to be. The longest time period available for growth rate forecasts of which I am aware is five years. The long-run growth rate (*i.e.*, the growth rate after the energy industry settles into a steady state, which is certainly *beyond* the next five years for this industry) drives the actual results one gets with the

DCF model. Unfortunately, this implies that unless the company or industry in question is stable, so there is little doubt as to the growth rate investors expect, DCF results in practice can end up being driven by the subjective judgment of the analyst who performs the work.

This is a problem at present because it is hard to imagine that today's energy industry would accurately be described as stable. Inflation and interest rates have largely stabilized over the last 10 years, but oil and natural gas prices have become more volatile recently. The electric power industry is one of the largest users of natural gas, but the status of deregulation is uncertain and the eventual structure of the industry is unknown. The prices of natural gas and petroleum have also exhibited a great deal of volatility recently, and the estimated total amount of recoverable natural gas in the Western Canada Sedimentary Basin is being revised downward. These factors plus the recent rapid increase in the price of natural gas makes demand more uncertain. Additionally, the electric industry as well as both the pipeline industry and the gas distribution sector are going through a series of mergers and acquisitions, which affects the companies' earnings growth rate estimates. This is one reason why companies involved in mergers and acquisitions are normally excluded from the sample. There has also been financial distress among companies specializing in trading natural gas and electricity products which affects both regulated and unregulated companies. Taken together, these factors mean that it may be some time before the energy industry settles into anything investors will see as a stable equilibrium.

Such circumstances imply that a regulator may often be faced with a wide range of DCF numbers, none of which can be well grounded in objective data on true long-run growth expectations, *because no such objective data now exist.* DCF for firms or industries in flux is *inherently* subjective with regard to a parameter (the long-run growth rate) that drives the answer one gets.

It is clear that much longer detailed growth rate forecasts than currently available from IBES and *Value Line* would be needed to implement the DCF model in a completely reliable way for these two samples at this time; however, the general stability of the 5-year growth rate forecasts for both samples indicates a higher degree of reliability than in the relatively recent past.

## C. DIVIDEND AND PRICE INPUTS

**Q15. What values do you use for dividends and stock prices?**

A15. Dividends are the last recorded dividend payments as reported by Compustat, the 3rd-quarter 2005 dividend. This dividend is grown at the estimated growth rate and divided by the price described below to estimate the dividend yield for the simple and multi-stage DCF models.

Stock prices are the average of the closing stock prices for the 15 trading days (approximately three weeks) ending January 3, 2006 for the Canadian utility sample and December 16, 2005 for the U.S. gas LDC sample. This time period coincides with the date the Globe Investor forecasts were obtained and with the date of the IBES growth forecasts.[8] I do not use a longer period to measure the price because that would be inconsistent with the principles that underlie the DCF formula. The DCF approach assumes the stock price is the present value of future expected dividends. Stock prices six months or a year ago reflect expectations at that time, which are different from those that underlie the currently available growth forecasts. At the same time, use of an average over a brief period helps guard against a company's price on a particular day price being unduly influenced by mistaken information, differences in trading frequency, and the like.

The closing stock price is used because it is at least as good as any other measure of the day's outcome, and may be better for DCF purposes. In particular, if there were any single price during the day that would affect investors' decisions to buy or sell a stock, I would suspect that it would be each day's closing price, not the high or low during the day. The daily price changes reported in the financial pages, for example, are from close to close, not from high to high or from low to low.

## D. COMPANY-SPECIFIC DCF COST OF CAPITAL ESTIMATES

**Q16. What DCF estimates do these data yield?**

A16. The cost of equity results for the simple and multi-stage DCF models are shown in Table No. MJV-6 for the Canadian utility sample and in Table No. MJV-17 for the U.S. gas LDC sample. Panel A reports the results for the simple DCF method, and Panel B reports

[8] The Canadian utility sample companies' growth rates were obtained on January 3, 2006.

the results for the multi-stage DCF method using the long-term GDP growth rate as the perpetual growth rate.

**Q17. What overall cost of capital estimates result from the DCF cost of equity estimates?**

A17. The capital structure, DCF cost of equity, and cost of debt estimates are combined to obtain the overall after-tax weighted-average cost of capital for each sample company. These results are presented in Table No. MJV-7 for the Canadian utility sample and Table No. MJV-18 for the U.S. gas LDC sample. Panel A relies on the simple DCF cost of equity results, and Panel B relies on the multi-stage DCF cost of equity results.

For Canadian sample, I also report the average for the subsample of companies that have had no dividend cuts or significant merger activities during the last five years and no significant accounting restatements.[9] For the U.S. gas LDC sample, the subsample companies are also characterized by earning more than 70 percent of their revenue from regulated activities.[10]

**Q18. What information do you report in Tables No. MJV-8 and MJV-19, Panels A and B?**

A18. These tables report the deemed equity thickness consistent with the sample's (and subsamples') estimated overall after-tax weighted-average cost of capital and a return on

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[9] Cascade Gas restated its earnings by $158,000 in the first quarter of 2004 as a result of remeasurement of retiree medical expenses. Given the company's annual revenues of $318 million this is a very small portion.

[10] The average for revenues from regulated businesses is above 80 percent for the Canadian utility subsample and above 95 percent for the U.S. gas LDC subsample. (See Table No. MJV-2 and Table No. MJV-13.)

equity of 9.63 percent (Panel A) and 8.89 percent (Panel B). For both the simple DCF and multistage DCF methods, the sample average ATWACC is reported in column one of Table No. MJV-8 and Table No. MJV-19. In the tables, column 8 of Panels A reports the deemed equity ratio at a 9.63 percent rate of return on equity while column 8 of Panels B reports the deemed equity ratio at a 8.89 percent rate of return on equity.

**Q19. What are the implications of these results?**

A19. The implication of these numbers is discussed in my written evidence, along with the findings of the equity risk premium approach.

Table No. MJV-1

Index to Tables for the Written Evidence of Michael J. Vilbert

Table No. MJV-2

2005 Canadian Utilities Sample

Percentage of Revenue from Regulated Activity in 2004 ($MM)

| Company | | Regulated Segment Description [1] | Revenues from Regulated Actvities [2] | Revenues from Unregulated Actvities [3] | Total Revenues [4] | Percentage from Regulated Activities [5] |
|---|---|---|---|---|---|---|
| Canadian Utilities | * | Utilities & Power Generation | $2,424.80 | $664.70 | $3,089.50 | 78.49% |
| Emera Inc | (*) | Electric Utilities | $1,095.70 | $126.30 | $1,222.00 | 89.66% |
| Enbridge Inc | * | Gas Sales & Transportation | $6,250.20 | $290.30 | $6,540.50 | 95.56% |
| TransCanada Corp | * | Gas Transmission | $3,917.00 | $1,190.00 | $5,107.00 | 76.70% |
| Fortis Inc | | Utilities | $884.36 | $260.92 | $1,145.29 | 77.22% |
| Gaz Metro L.P. | | Natural Gas Distribution | $1,717.70 | $65.20 | $1,782.90 | 96.34% |
| Full Sample | | | | | | 85.66% |
| Subsample* | | | | | | 85.10% |

Sources and Notes:
[1], [2] and [4]: Company Annual Reports for 2004.
[3]: [4] - [2].
[5]: [2] / [4].
* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.
Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps.
See Workpaper #1 To Table No. MJV-11.
In this subsample average, Emera is included.

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel A: Canadian Utilities

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $2,176 | $2,118 | [a] |
| Shares Outstanding (in millions) - Common | 127 | 127 | [b] |
| Price per Share - Common | $43.13 | $30.25 | [c] |
| Market Value of Common Equity | $5,476 | $3,835 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 2.52 | 1.81 | [e] = [d] / [a] |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $637 | $637 | [f] |
| Market Value of Preferred Equity | $637 | $637 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $1,090 | $1,270 | [h] |
| Current Liabilities | $331 | $397 | [i] |
| Current Portion of Long-Term Debt | $56 | $56 | [j] |
| Net Working Capital | $815 | $929 | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $1 | $1 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | [m] = See Sources and Notes. |
| Long-Term Debt | $2,773 | $2,932 | [n] |
| Book Value of Long-Term Debt | $2,829 | $2,988 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $3,376 | $3,376 | [p] |
| Market Value of Debt | $3,376 | $3,376 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $9,488 | $7,848 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 57.71% | 48.87% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | 6.71% | 8.11% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 35.58% | 43.02% | [u] = [q] / [r]. |

Sources and Notes:
Compustat as of January 3, 2006.
Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[j] and [l]: Canadian Utilities did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.
[m] =
(1) 0 if [k] > 0.
(2) The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3) [l] if [k] < 0 and |[k]| > [l].
Canadian Utilities has both Class A and Class B shares traded on TSX. Both classes are included in the number of shares.
Compustat does not report prices for Class B shares. Class A share prices were used to calculate the Market Value of Equity.

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel B: Emera Inc

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $1,348 | $1,337 | [a] |
| Shares Outstanding (in millions) - Common | 110 | 109 | [b] |
| Price per Share - Common | $20.53 | $19.34 | [c] |
| Market Value of Common Equity | $2,256 | $2,105 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.67 | 1.57 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $487 | $330 | [h] |
| Current Liabilities | $855 | $489 | [i] |
| Current Portion of Long-Term Debt | $101 | $101 | [j] |
| Net Working Capital | ($267) | ($58) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $145 | $145 | [l] |
| Adjusted Short-Term Debt | $145 | $58 | [m] = See Sources and Notes. |
| Long-Term Debt | $1,427 | $1,627 | [n] |
| Book Value of Long-Term Debt | $1,528 | $1,727 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $1,853 | $1,853 | [p] |
| Market Value of Debt | $1,998 | $1,911 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $4,254 | $4,016 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 53.03% | 52.42% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 46.97% | 47.58% | [u] = [q] / [r]. |

Sources and Notes:
Compustat as of January 3, 2006.
Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.
Prices are reported in Workpaper #1 to Table No. MJV-6
[j] and [l]: Emera Inc did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.
[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel C: Enbridge Inc

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $4,038 | $3,853 | [a] |
| Shares Outstanding (in millions) - Common | 348 | 346 | [b] |
| Price per Share - Common | $36.27 | $29.64 | [c] |
| Market Value of Common Equity | $12,633 | $10,260 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 3.13 | 2.66 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $125 | $125 | [f] |
| Market Value of Preferred Equity | $125 | $125 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $2,498 | $2,349 | [h] |
| Current Liabilities | $2,841 | $2,744 | [i] |
| Current Portion of Long-Term Debt | $734 | $734 | [j] |
| Net Working Capital | $392 | $339 | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $651 | $651 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | [m] = See Sources and Notes. |
| Long-Term Debt | $7,633 | $6,719 | [n] |
| Book Value of Long-Term Debt | $8,367 | $7,453 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $8,100 | $8,100 | [p] |
| Market Value of Debt | $8,100 | $8,100 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $20,859 | $18,486 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 60.57% | 55.50% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | 0.60% | 0.68% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 38.83% | 43.82% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of January 3, 2006.

Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[j] and [l]: Enbridge Inc did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel D: Transcanada Corp

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $6,992 | $6,565 | [a] |
| Shares Outstanding (in millions) - Common | 487 | 485 | [b] |
| Price per Share ($) - Common | $36.91 | $29.77 | [c] |
| Market Value of Common Equity | $17,972 | $14,436 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 2.57 | 2.20 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $1,358 | $1,109 | [h] |
| Current Liabilities | $2,223 | $2,744 | [i] |
| Current Portion of Long-Term Debt | $849 | $849 | [j] |
| Net Working Capital | ($16) | ($786) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $546 | $546 | [l] |
| Adjusted Short-Term Debt | $16 | $546 | [m] = See Sources and Notes. |
| Long-Term Debt | $10,941 | $10,511 | [n] |
| Book Value of Long-Term Debt | $11,790 | $11,360 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $13,169 | $13,169 | [p] |
| Market Value of Debt | $13,185 | $13,715 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $31,157 | $28,151 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 57.68% | 51.28% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 42.32% | 48.72% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of January 3, 2006.

Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[j] and [l]: Transcanada Corp did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel E: Fortis Inc

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $1,205 | $1,000 | [a] |
| Shares Outstanding (in millions) - Common | 103 | 96 | [b] |
| Price per Share ($) - Common | $24.14 | $17.52 | [c] |
| Market Value of Common Equity | $2,488 | 1,674.08 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 2.07 | 1.67 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $319 | $320 | [f] |
| Market Value of Preferred Equity | $319 | $320 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $248 | $257 | [h] |
| Current Liabilities | $386 | $538 | [i] |
| Current Portion of Long-Term Debt | $36 | $36 | [j] |
| Net Working Capital | ($101) | ($245) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $193 | $193 | [l] |
| Adjusted Short-Term Debt | $101 | $193 | [m] = See Sources and Notes. |
| Long-Term Debt | $2,026 | $1,879 | [n] |
| Book Value of Long-Term Debt | $2,062 | $1,915 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $2,134 | $2,134 | [p] |
| Market Value of Debt | $2,235 | $2,327 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | | | |
| | $5,043 | $4,320 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 49.34% | 38.75% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | 6.34% | 7.40% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 44.32% | 53.85% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of January 3, 2006.

Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[j] and [l]: Fortis Inc did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-3

Market Value of the 2005 Canadian Utilities Sample

Panel F: Gaz Metro L.P.

($MM)

| | DCF Capital Structure | Year End, 2004 | Notes |
|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | |
| Book Value, Common Shareholder's Equity | $938 | $913 | [a] |
| Shares Outstanding (in millions) - Common | 118 | 115 | [b] |
| Price per Share - Common | $19.94 | $23.03 | [c] |
| Market Value of Common Equity | $2,343 | $2,637 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 2.50 | 2.89 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | |
| Book Value of Preferred Equity | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | |
| Current Assets | $378 | $452 | [h] |
| Current Liabilities | $291 | $382 | [i] |
| Current Portion of Long-Term Debt | $46 | $46 | [j] |
| Net Working Capital | $133 | $117 | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $29 | $29 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | [m] = See Sources and Notes. |
| Long-Term Debt | $1,354 | $1,286 | [n] |
| Book Value of Long-Term Debt | $1,400 | $1,332 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $1,344 | $1,344 | [p] |
| Market Value of Debt | $1,344 | $1,344 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $3,687 | $3,981 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | |
| Common Equity - Market Value Ratio | 63.56% | 66.25% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 36.44% | 33.75% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of January 3, 2006.

Capital structure from Year End, 2004 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 1/3/2006.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[j] and [l]: Gaz Metro L.P. did not report the Current Portion of Long-Term Debt, or Notes Payable for 3rd Quarter, 2005 (DCF Capital Structure). The numbers are set to those for Year End, 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-4

2005 Canadian Utilities Sample

Capital Structure Summary

| Company | | DCF Capital Structure | | | 52-Week Average Capital Structure | | |
|---|---|---|---|---|---|---|---|
| | | Common Equity - Value Ratio [1] | Preferred Equity - Value Ratio [2] | Debt - Value Ratio [3] | Common Equity - Value Ratio [4] | Preferred Equity - Value Ratio [5] | Debt - Value Ratio [6] |
| Canadian Utilities | * | 0.58 | 0.07 | 0.36 | 0.53 | 0.07 | 0.39 |
| Emera Inc | (*) | 0.53 | - | 0.47 | 0.53 | - | 0.47 |
| Enbridge Inc | * | 0.61 | 0.01 | 0.39 | 0.58 | 0.01 | 0.41 |
| Transcanada Corp | * | 0.58 | - | 0.42 | 0.54 | - | 0.46 |
| Fortis Inc | | 0.49 | 0.06 | 0.44 | 0.44 | 0.07 | 0.49 |
| Gaz Metro L.P. | | 0.64 | - | 0.36 | 0.65 | - | 0.35 |
| Full Sample | | 0.57 | 0.02 | 0.41 | 0.55 | 0.02 | 0.43 |
| Subsample* | | 0.57 | 0.02 | 0.41 | 0.55 | 0.03 | 0.42 |

Sources and Notes:
[1], [4]:Workpaper #1 to Table No. MJV-4.
[2], [5]:Workpaper #2 to Table No. MJV-4.
[3], [6]:Workpaper #3 to Table No. MJV-4.
Values in this table may not add up to one because of rounding.
* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.
Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps.
See Workpaper #1 To Table No. MJV-11.

Workpaper #1 to Table No. MJV-4

2005 Canadian Utilities Sample

Calculation of the Average Common Equity - Market Value Ratio

| Company | DCF Capital Structure [1] | 2004 [2] | 52-Week Average [3] |
|---|---|---|---|
| Canadian Utilities | 0.58 | 0.49 | 0.53 |
| Emera Inc | 0.53 | 0.52 | 0.53 |
| Enbridge Inc | 0.61 | 0.56 | 0.58 |
| Transcanada Corp | 0.58 | 0.51 | 0.54 |
| Fortis Inc | 0.49 | 0.39 | 0.44 |
| Gaz Metro L.P. | 0.64 | 0.66 | 0.65 |

Sources and Notes:
[1] - [2]: Table No. MJV-3; Panels A - F, [s].
[3]: {(1/2) x [1]} + {(1/2) x [2]}.

## Workpaper #2 to Table No. MJV-4

## 2005 Canadian Utilities Sample

## Calculation of the Average Preferred Equity - Market Value Ratio

| Company | DCF Capital Structure [1] | 2004 [2] | 52-Week Average [3] |
|---|---|---|---|
| Canadian Utilities | 0.07 | 0.08 | 0.07 |
| Emera Inc | - | - | - |
| Enbridge Inc | 0.01 | 0.01 | 0.01 |
| Transcanada Corp | - | - | - |
| Fortis Inc | 0.06 | 0.07 | 0.07 |
| Gaz Metro L.P. | - | - | - |

Sources and Notes:
[1] - [2]: Table No. MJV-3; Panels A - F, [t].
[3]: {(1/2) x [1]} + {(1/2) x [2]}.

Workpaper #3 to Table No. MJV-4

2005 Canadian Utilities Sample

Calculation of the Average Debt - Market Value Ratio

| Company | DCF Capital Structure [1] | 2004 [2] | 52-Week Average [3] |
|---|---|---|---|
| Canadian Utilities | 0.36 | 0.43 | 0.39 |
| Emera Inc | 0.47 | 0.48 | 0.47 |
| Enbridge Inc | 0.39 | 0.44 | 0.41 |
| Transcanada Corp | 0.42 | 0.49 | 0.46 |
| Fortis Inc | 0.44 | 0.54 | 0.49 |
| Gaz Metro L.P. | 0.36 | 0.34 | 0.35 |

Sources and Notes:
[1] - [2]: Table No. MJV-3; Panels A - F, [u].
[3]: {(1/2) x [1]} + {(1/2) x [2]}.

Workpaper #4 to Table No. MJV-4

2005 Canadian Utilities Sample

Equity Ratio

| | Debt-Equity Ratio [1] | Equity Ratio [2] | Preferred Ratio [3] | Debt Ratio [4] |
|---|---|---|---|---|
| Full Sample | 0.87 | 0.53 | 0.02 | 0.44 |
| Subsample* | 0.83 | 0.55 | 0.03 | 0.43 |

Sources and Notes:
[1]: Workpaper #5 to Table No. MJV-4, [3].
[2]: 1 / (1 + [1] ).
[3]: Table No. MJV-4, [5].
[4]: 1 - [2] - [3].
* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.
Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps.
See Workpaper #1 To Table No. MJV-11.

# Workpaper #5 to Table No. MJV-4

## 2005 Canadian Utilities Sample

## Debt/Equity Ratios

| | | 3rd Quarter, 2005<br>[1] | Year End, 2004<br>[2] | 52-Week Average<br>[3] |
|---|---|---|---|---|
| Canadian Utilities | * | 0.78 | 1.05 | 0.91 |
| Emera Inc | (*) | 0.92 | 0.91 | 0.91 |
| Enbridge Inc | * | 0.63 | 0.80 | 0.72 |
| Transcanada Corp | * | 0.74 | 0.95 | 0.85 |
| Fortis Inc | | 1.06 | 1.58 | 1.32 |
| Gaz Metro L.P. | | 0.51 | 0.51 | 0.51 |
| Full Sample | | | | 0.87 |
| Subsample* | | | | 0.83 |

Sources and Notes:
[1] - [2]: Table No. MJV-3, Panels A - F, ( [q] + [g] ) / [d].
[3]: {(1/2) x [1]} + {(1/2) x [2]}.
* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.
Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps.
See Workpaper #1 To Table No. MJV-11.

## Table No. MJV-5

## 2005 Canadian Utilities Sample

## Analyst Estimated Growth Rates

| Company | Analyst Long-Term Growth Rate [1] | Number of Estimates [2] |
|---|---|---|
| Canadian Utilities | 3.0% | 1 |
| Emera Inc | 5.0% | 1 |
| Enbridge Inc | 7.0% | 5 |
| Transcanada Corp | 5.0% | 3 |
| Fortis Inc | 5.0% | 1 |
| Gaz Metro L.P. | n/a | n/a |

Sources and Notes:

[1], [2]: http://www.globeinvestor.com/

The source does not report the precise release date of the earnings forecasts.

The information was obtained on January 3, 2006.

Data provided to the Globe Investor by Thompson Research.

## Table No. MJV-6

## DCF Cost of Equity of the 2005 Canadian Utilities Sample

### Panel A: Simple DCF Method (Quarterly)

| Company | Stock Price [1] | Quarterly Dividend Q3, 2005 [2] | Analyst Long-Term Growth Rate [3] | Quarterly Growth Rate [4] | DCF Cost of Equity [5] |
|---|---|---|---|---|---|
| Canadian Utilities | $43.13 | $0.28 | 3.0% | 0.7% | 5.7% |
| Emera Inc | $20.53 | $0.22 | 5.0% | 1.2% | 9.6% |
| Enbridge Inc | $36.27 | $0.25 | 7.0% | 1.7% | 10.0% |
| Transcanada Corp | $36.91 | $0.31 | 5.0% | 1.2% | 8.5% |
| Fortis Inc | $24.14 | $0.14 | 5.0% | 1.2% | 7.5% |

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-6.

[2]: Workpaper #2 to Table No. MJV-6.

[3]: Table No. MJV-5, [1].

[4]: {(1 + [3]) ^ (1/4)} - 1.

[5]: {(([2] / [1]) x (1 + [4]) + [4] + 1) ^ 4} - 1.

Gaz Metro LP is excluded because they do not have a growth forecast reported by the Globe Investor.

Table No. MJV-6

DCF Cost of Equity of the 2005 Canadian Utilities Sample

Panel B: Multi-Stage DCF (Using the International Energy Outlook Long-Term GDP Growth Forecast as the Perpetual Rate)

| Company | Stock Price [1] | Quarterly Dividend Q3, 2005 [2] | Analyst Long-Term Growth Rate [3] | Combined Growth Rate: FY 10 - 11 [4] | Combined Growth Rate: FY 11 - 12 [5] | Combined Growth Rate: FY 12 - 13 [6] | Combined Growth Rate: FY 13 - 14 [7] | Combined Growth Rate: FY 14 - 15 [8] | GDP Long-Term Growth Rate [9] | DCF Cost of Equity [10] |
|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities | $43.13 | $0.28 | 3.0% | 3.2% | 3.4% | 3.7% | 3.9% | 4.1% | 4.3% | 6.8% |
| Emera Inc | $20.53 | $0.22 | 5.0% | 4.9% | 4.8% | 4.7% | 4.6% | 4.5% | 4.3% | 9.1% |
| Enbridge Inc | $36.27 | $0.25 | 7.0% | 6.6% | 6.1% | 5.7% | 5.2% | 4.8% | 4.3% | 7.8% |
| Transcanada Corp | $36.91 | $0.31 | 5.0% | 4.9% | 4.8% | 4.7% | 4.6% | 4.5% | 4.3% | 8.0% |
| Fortis Inc | $24.14 | $0.14 | 5.0% | 4.9% | 4.8% | 4.7% | 4.6% | 4.5% | 4.3% | 6.9% |

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-6.

[2]: Workpaper #2 to Table No. MJV-6.

[3]: Table No. MJV-5, [1].

[4]: [3] - { ([3] - [9]) / 6 }.

[5]: [4] - { ([3] - [9]) / 6 }.

[6]: [5] - { ([3] - [9]) / 6 }.

[7]: [6] - { ([3] - [9]) / 6 }.

[8]: [7] - { ([3] - [9]) / 6 }.

[9]: Real GDP growth rate from International Energy Outlook, 2005 and inflation from Consensus Forecast, January 9, 2006.

[10]: Workpaper #3 to Table No. MJV-6.

Gaz Metro LP is excluded because they do not have a growth forecast reported by the Globe Investor.

Workpaper #1 to Table No. MJV-6

2005 Canadian Utilities Sample

Common Stock Prices from December 9, 2005 to January 3, 2006

| Company | 03-Jan-06 | 02-Jan-06 | 30-Dec-05 | 29-Dec-05 | 28-Dec-05 | 27-Dec-05 | 26-Dec-05 | 23-Dec-05 | 22-Dec-05 | 21-Dec-05 | 20-Dec-05 | 19-Dec-05 | 16-Dec-05 | 15-Dec-05 | 14-Dec-05 | 13-Dec-05 | 12-Dec-05 | 09-Dec-05 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities | $43.43 | - | $43.98 | $43.25 | $43.22 | - | - | $43.26 | $43.79 | $42.81 | $42.15 | $41.75 | $41.00 | $42.50 | $42.81 | $43.50 | $44.33 | $45.20 | $43.13 |
| Emera Inc | $20.86 | - | $21.04 | $20.93 | $20.71 | - | - | $20.75 | $20.77 | $20.76 | $20.42 | $20.30 | $20.14 | $20.50 | $20.15 | $20.25 | $19.97 | $20.37 | $20.53 |
| Enbridge Inc | $36.80 | - | $36.34 | $36.69 | $36.75 | - | - | $36.77 | $36.55 | $36.44 | $36.32 | $36.43 | $36.56 | $36.18 | $35.70 | $35.57 | $35.46 | $35.50 | $36.27 |
| Transcanada Corp | $37.01 | - | $36.65 | $36.66 | $36.30 | - | - | $36.93 | $36.79 | $37.27 | $37.55 | $37.45 | $37.56 | $36.53 | $36.81 | $36.86 | $36.60 | $36.61 | $36.91 |
| Fortis Inc | $24.38 | - | $24.27 | $24.20 | $24.01 | - | - | $24.51 | $24.60 | $23.92 | $23.78 | $23.81 | $23.79 | $24.15 | $24.74 | $23.90 | $23.50 | $24.55 | $24.14 |
| Gaz Metro L.P | $19.80 | - | $19.57 | $19.77 | $19.77 | - | - | $19.82 | $19.98 | $20.00 | $19.65 | $19.55 | $19.08 | $19.72 | $20.50 | $20.32 | $20.68 | $20.89 | $19.94 |

Sources and Notes:
Compustat as of January 3, 2006.

Workpaper #2 to Table No. MJV-6

2005 Canadian Utilities Sample

3rd Quarter 2005 Dividend Payments

| Company | Q3, 2005 |
| --- | --- |
| Canadian Utilities | $0.28 |
| Emera Inc | $0.22 |
| Enbridge Inc | $0.25 |
| Transcanada Corp | $0.31 |
| Fortis Inc | $0.14 |

Compustat as of January 3, 2006.

Workpaper #3 to Table No. MJV-6

DCF Cost of Equity of the 2005 Canadian Utilities Sample

Multi - Stage DCF (using the Energy International Outlook Long-Term GDP Growth Rate Forecast as the Perpetual Growth Rate)

| Year | Company | Canadian Utilities | Emera Inc | Enbridge Inc | Transcanada Corp | Fortis Inc |
|---|---|---|---|---|---|---|
| | Current Stock Price | ($43.13) | ($20.53) | ($36.27) | ($36.91) | ($24.14) |
| YEAR 2005 | Dividend Q4 Estimate | $0.28 | $0.23 | $0.25 | $0.31 | $0.14 |
| YEAR 2006 | Dividend Q1 Estimate | $0.28 | $0.23 | $0.26 | $0.31 | $0.15 |
| YEAR 2006 | Dividend Q2 Estimate | $0.28 | $0.23 | $0.26 | $0.32 | $0.15 |
| YEAR 2006 | Dividend Q3 Estimate | $0.28 | $0.23 | $0.27 | $0.32 | $0.15 |
| YEAR 2006 | Dividend Q4 Estimate | $0.29 | $0.24 | $0.27 | $0.32 | $0.15 |
| YEAR 2007 | Dividend Q1 Estimate | $0.29 | $0.24 | $0.28 | $0.33 | $0.15 |
| YEAR 2007 | Dividend Q2 Estimate | $0.29 | $0.24 | $0.28 | $0.33 | $0.16 |
| YEAR 2007 | Dividend Q3 Estimate | $0.29 | $0.25 | $0.29 | $0.34 | $0.16 |
| YEAR 2007 | Dividend Q4 Estimate | $0.29 | $0.25 | $0.29 | $0.34 | $0.16 |
| YEAR 2008 | Dividend Q1 Estimate | $0.30 | $0.25 | $0.30 | $0.34 | $0.16 |
| YEAR 2008 | Dividend Q2 Estimate | $0.30 | $0.25 | $0.30 | $0.35 | $0.16 |
| YEAR 2008 | Dividend Q3 Estimate | $0.30 | $0.26 | $0.31 | $0.35 | $0.16 |
| YEAR 2008 | Dividend Q4 Estimate | $0.30 | $0.26 | $0.31 | $0.36 | $0.17 |
| YEAR 2009 | Dividend Q1 Estimate | $0.30 | $0.26 | $0.32 | $0.36 | $0.17 |
| YEAR 2009 | Dividend Q2 Estimate | $0.31 | $0.27 | $0.32 | $0.37 | $0.17 |
| YEAR 2009 | Dividend Q3 Estimate | $0.31 | $0.27 | $0.33 | $0.37 | $0.17 |
| YEAR 2009 | Dividend Q4 Estimate | $0.31 | $0.27 | $0.33 | $0.38 | $0.18 |
| YEAR 2010 | Dividend Q1 Estimate | $0.31 | $0.28 | $0.34 | $0.38 | $0.18 |
| YEAR 2010 | Dividend Q2 Estimate | $0.32 | $0.28 | $0.34 | $0.38 | $0.18 |
| YEAR 2010 | Dividend Q3 Estimate | $0.32 | $0.28 | $0.35 | $0.39 | $0.18 |
| YEAR 2010 | Dividend Q4 Estimate | $0.32 | $0.29 | $0.36 | $0.39 | $0.18 |
| YEAR 2011 | Dividend Q1 Estimate | $0.32 | $0.29 | $0.36 | $0.40 | $0.19 |
| YEAR 2011 | Dividend Q2 Estimate | $0.33 | $0.29 | $0.37 | $0.40 | $0.19 |
| YEAR 2011 | Dividend Q3 Estimate | $0.33 | $0.30 | $0.37 | $0.41 | $0.19 |
| YEAR 2011 | Dividend Q4 Estimate | $0.33 | $0.30 | $0.38 | $0.41 | $0.19 |
| YEAR 2012 | Dividend Q1 Estimate | $0.33 | $0.31 | $0.39 | $0.42 | $0.20 |
| YEAR 2012 | Dividend Q2 Estimate | $0.34 | $0.31 | $0.39 | $0.42 | $0.20 |
| YEAR 2012 | Dividend Q3 Estimate | $0.34 | $0.31 | $0.40 | $0.43 | $0.20 |
| YEAR 2012 | Dividend Q4 Estimate | $0.34 | $0.32 | $0.40 | $0.43 | $0.20 |
| YEAR 2013 | Dividend Q1 Estimate | $0.35 | $0.32 | $0.41 | $0.44 | $0.20 |
| YEAR 2013 | Dividend Q2 Estimate | $0.35 | $0.32 | $0.41 | $0.44 | $0.21 |
| YEAR 2013 | Dividend Q3 Estimate | $0.35 | $0.33 | $0.42 | $0.45 | $0.21 |
| YEAR 2013 | Dividend Q4 Estimate | $0.36 | $0.33 | $0.43 | $0.45 | $0.21 |
| YEAR 2014 | Dividend Q1 Estimate | $0.36 | $0.33 | $0.43 | $0.46 | $0.21 |
| YEAR 2014 | Dividend Q2 Estimate | $0.36 | $0.34 | $0.44 | $0.46 | $0.22 |
| YEAR 2014 | Dividend Q3 Estimate | $0.37 | $0.34 | $0.44 | $0.47 | $0.22 |
| YEAR 2014 | Dividend Q4 Estimate | $0.37 | $0.35 | $0.45 | $0.47 | $0.22 |
| YEAR 2015 | Dividend Q1 Estimate | $0.37 | $0.35 | $0.45 | $0.48 | $0.22 |
| YEAR 2015 | Dividend Q2 Estimate | $0.38 | $0.35 | $0.46 | $0.48 | $0.23 |
| YEAR 2015 | Dividend Q3 Estimate | $0.38 | $0.36 | $0.46 | $0.49 | $0.23 |
| YEAR 2015 Q4 | Year 10 Stock Price | $66.43 | $32.21 | $57.65 | $57.76 | $37.67 |
| | Trial COE: Quarterly Rate | 1.7% | 2.2% | 1.9% | 1.9% | 1.7% |
| | Trial COE: Annual Rate | 6.8% | 9.1% | 7.8% | 8.0% | 6.9% |
| | Cost of Equity | 6.8% | 9.1% | 7.8% | 8.0% | 6.9% |
| | (Trial COE - COE) x 100 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Sources and Notes:

All Growth Rate Estimates: Table No. MJV-6; Panel B.

Stock Prices and Dividends are from Compustat as of January 3, 2006.

1. See Workpaper #1 to Table No. MJV-6 for the average closing stock price obtained from Compustat.
2. See Workpaper #2 to Table No. MJV-6 for the for the quarterly dividend obtained from Compustat.
3. The Energy International Outlook Long-Term GDP Growth Rate and Consensus Forecast Inflation Rate is used to calculate the Year 10 Stock Price.
   {(the Dividend Year 2015 Q3 Estimate) x ((1 + the Perpetual Growth Rate) ^ (1/2))} /
   {(Trial COE - Quarterly Rate) - ((1 + the Perpetual Growth Rate) ^ (1/4) -1)}.

Table No. MJV-7

Overall Cost of Capital of the 2005 Canadian Utilities Sample

Panel A: Simple DCF Method (Quarterly)

| Company | | January, 2006 Bond Rating [1] | January, 2006 Preferred Stock Rating [2] | DCF Cost of Equity [3] | DCF Common Equity to Market Value Ratio [4] | Cost of Preferred Equity [5] | DCF Preferred Equity to Market Value Ratio [6] | Cost of Debt [7] | DCF Debt to Market Value Ratio [8] | Union's Income Tax Rate [9] | Overall After- Tax Cost of Capital [10] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities | * | A | A | 5.7% | 0.58 | 4.9% | 0.07 | 4.9% | 0.36 | 36.1% | 4.7% |
| Emera Inc | * | BBB | - | 9.6% | 0.53 | - | - | 5.3% | 0.47 | 36.1% | 6.7% |
| Enbridge Inc | * | A | A | 10.0% | 0.61 | 4.9% | 0.01 | 4.9% | 0.39 | 36.1% | 7.3% |
| Transcanada Corp | * | A | - | 8.5% | 0.58 | - | - | 4.9% | 0.42 | 36.1% | 6.2% |
| Fortis Inc | | BBB | BBB | 7.5% | 0.49 | 5.3% | 0.06 | 5.3% | 0.44 | 36.1% | 5.5% |
| Average [a] | | | | 8.3% | 0.56 | 5.0% | 0.03 | 5.1% | 0.42 | 36.1% | 6.1% |
| Average [b] | | | | 8.4% | 0.57 | 4.9% | 0.04 | 5.0% | 0.41 | 36.1% | 6.2% |

Sources and Notes:

[1]: Dominion Bond Rating Service, January 23, 2006.

[2]: Preferred ratings were assumed equal to debt ratings.

[3]: Table No. MJV-6; Panel A, [5].

[4]: Table No. MJV-4, [1].

[5]: [7].

[6]: Table No. MJV-4, [2].

[7]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005.

[8]: Table No. MJV-4, [3].

[9]: Provided by Union.

[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.

[a]: Average of All Companies with a Cost of Equity greater than Cost of Debt plus 25 bps.

[b]: Average of Companies that have no significant merger activity, no dividend cuts for five years, and no data issues.

* Companies marked with an asterix represent those with no mergers and acquisitions or dividend cuts for five years and no data issues.

Table No. MJV-7

Overall Cost of Capital of the 2005 Canadian Utilities Sample

Panel B: Multi-Stage DCF (Using the International Energy Outlook Long-Term GDP Growth Forecast as the Perpetual Rate)

| Company | | January, 2006 Bond Rating [1] | January, 2006 Preferred Stock Rating [2] | DCF Cost of Equity [3] | DCF Common Equity to Market Value Ratio [4] | Cost of Preferred Equity [5] | DCF Preferred Equity to Market Value Ratio [6] | Cost of Debt [7] | DCF Debt to Market Value Ratio [8] | Union's Income Tax Rate [9] | Overall After- Tax Cost of Capital [10] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities | * | A | A | 6.8% | 0.58 | 4.9% | 0.07 | 4.9% | 0.36 | 36.1% | 5.4% |
| Emera Inc | * | BBB | - | 9.1% | 0.53 | - | - | 5.3% | 0.47 | 36.1% | 6.4% |
| Enbridge Inc | * | A | A | 7.8% | 0.61 | 4.9% | 0.01 | 4.9% | 0.39 | 36.1% | 6.0% |
| Transcanada Corp | * | A | - | 8.0% | 0.58 | - | - | 4.9% | 0.42 | 36.1% | 5.9% |
| Fortis Inc | | BBB | BBB | 6.9% | 0.49 | 5.3% | 0.06 | 5.3% | 0.44 | 36.1% | 5.3% |
| Average [a] | | | | 7.7% | 0.56 | 5.0% | 0.03 | 5.1% | 0.42 | 36.1% | 5.8% |
| Average [b] | | | | 7.9% | 0.57 | 4.9% | 0.04 | 5.0% | 0.41 | 36.1% | 5.9% |

Sources and Notes:

[1]: Dominion Bond Rating Service, January 23, 2006.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-6; Panel B, [10].
[4]: Table No. MJV-4, [1].
[5]: [7].
[6]: Table No. MJV-4, [2].
[7]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005.
[8]: Table No. MJV-4, [3].
[9]: Provided by Union.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[a]: Average of All Companies with a Cost of Equity greater than Cost of Debt plus 25 bps.
[b]: Average of Companies that have no significant merger activity, no dividend cuts for five years, and no data issues.
* Companies marked with an asterix represent those with no mergers and acquisitions or dividend cuts for five years and no data issues.

Table No. MJV-8

Deemed Capital Structure Consistent with 2005 Canadian Utilities Sample's DCF Cost of Capital Estimates

**Panel A: Using Union's Allowed ROE: 9.63%**

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using All Companies** | | | | | | | | |
| Simple DCF Quarterly | 6.1% | 51.2% | 4.9% | 36.12% | 3.2% | 4.9% | 9.63% | 45.6% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 5.8% | 56.0% | 4.9% | 36.12% | 3.2% | 4.9% | 9.63% | 40.8% |
| **Using Companies that have no significant merger activity, no dividend cuts for five years and no data issues.** | | | | | | | | |
| Simple DCF Quarterly | 6.2% | 49.1% | 4.9% | 36.12% | 3.2% | 4.9% | 9.63% | 47.7% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 5.9% | 53.9% | 4.9% | 36.12% | 3.2% | 4.9% | 9.63% | 42.8% |

Sources and Notes:

[1]: Table No. MJV-7, Panels A-B, [10].

[2]: 1 - [5] - [8].

[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

Table No. MJV-8

Deemed Capital Structure Consistent with 2005 Canadian Utilities Sample's DCF Cost of Capital Estimates

2005 Canadian Utilities Sample Information

**Panel B: Using Union's Estimated ROE for 2006: 8.89%**

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using All Companies** | | | | | | | | |
| Simple DCF Quarterly | 6.1% | 45.3% | 4.9% | 36.12% | 3.2% | 4.9% | 8.89% | 51.5% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 5.8% | 50.7% | 4.9% | 36.12% | 3.2% | 4.9% | 8.89% | 46.1% |
| **Using Companies that have no significant merger activity, no dividend cuts for five years and no data issues.** | | | | | | | | |
| Simple DCF Quarterly | 6.2% | 42.9% | 4.9% | 36.12% | 3.2% | 4.9% | 8.89% | 53.9% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 5.9% | 48.4% | 4.9% | 36.12% | 3.2% | 4.9% | 8.89% | 48.4% |

Sources and Notes:
[1]: Table No. MJV-7; Panels A-B, [10].
[2]: 1 - [5] - [8].
[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.
[4]: Provided by Union.
[5]: Provided by Union.
[6]: Cost of preferred equity assumed equal to cost of debt
[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.
[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

Table No. MJV-9

2005 Canadian Utilities Sample

Computation of Risk-Free Rates

| | | |
|---|---|---|
| [1] | 3-Month Consensus Risk-Free Rate Forecast | 4.00% |
| [2] | 10-Year Consensus Risk-Free Rate Forecast | 4.60% |
| [3] | Maturity Premium | 0.20% |
| [4] | Long-Term Risk-Free Rate (rounded to the nearest 5 basis points) | 4.80% |

Sources and Notes:
[1] - [2]: Consensus Forecast, January 9, 2006.
[3]: See Workpaper #2 to Table No. MJV-9, Panel C.
[4]: [2] + [3].

Workpaper #1 to Table No. MJV-9

2005 Canadian Utilities Sample

Historical Market Risk Premiums

| | Long-Term Return on Market [1] | Total Return on 91-Day T-Bills [2] | Total Return on 10 yr+ Gov. Bonds [3] | **Short-Term Risk Premium** [4] | **Long-Term Return on Market - Long-Term Total Return** [5] | **Ibbotson Long-Term Risk Premium** [6] |
|---|---|---|---|---|---|---|
| 1951-2004 | 11.5% | 6.4% | 7.3% | 5.1% | 4.2% | 4.2% |
| 1948-2004 | 12.3% | 6.1% | 6.9% | 6.3% | 5.4% | 5.3% |
| 1936-2004 | 11.4% | 5.1% | 6.5% | 6.3% | 4.9% | 5.1% |
| 1934-2004 | 11.8% | 5.0% | 6.6% | 6.8% | 5.2% | - |
| 1924-2004 | 11.6% | - | 6.4% | - | 5.2% | - |

Sources and Notes:

[1] - [3]: Computed from Report on Canadian Economic Statistics, March 2005, Table 1A.

[4]: [1] - [2].

[5]: [1] - [3].

[6]: Ibbotson Associates, Canadian Risk Premia Over Time Report, 2005.

Workpaper #2 to Table No. MJV-9

2005 Canadian Utilities Sample

Panel A: Canadian Bond Historical Averages (Annual Series Data)

| | 91-Day T-Bill Yield [1] | 1-3 Year Bond Yields [2] | 3-5 Year Bond Yields [3] | 5-10 Year Bond Yields [4] | Long-Term Government Bond Yield [5] |
|---|---|---|---|---|---|
| **1936** | 0.85% | | | | 2.97% |
| **1937** | 0.72% | | | | 3.17% |
| **1938** | 0.60% | | | | 3.09% |
| **1939** | 0.71% | | | | 3.16% |
| **1940** | 0.71% | | | | 3.28% |
| **1941** | 0.58% | | | | 3.10% |
| **1942** | 0.54% | | | | 3.06% |
| **1943** | 0.48% | | | | 3.01% |
| **1944** | 0.39% | | | | 3.00% |
| **1945** | 0.36% | | | | 2.93% |
| **1946** | 0.39% | | | | 2.61% |
| **1947** | 0.41% | | | | 2.57% |
| **1948** | 0.41% | | | | 2.93% |
| **1949** | 0.49% | 1.65% | | | 2.87% |
| **1950** | 0.55% | 1.80% | | | 2.86% |
| **1951** | 0.79% | 2.42% | 2.61% | 3.08% | 3.23% |
| **1952** | 1.07% | 2.81% | 3.24% | 3.56% | 3.56% |
| **1953** | 1.72% | 3.21% | 3.45% | 3.63% | 3.71% |
| **1954** | 1.43% | 2.18% | 2.67% | 2.90% | 3.18% |
| **1955** | 1.63% | 2.19% | 2.79% | 2.87% | 3.14% |
| **1956** | 2.96% | 3.60% | 3.76% | 3.75% | 3.63% |
| **1957** | 3.81% | 4.46% | 4.57% | 4.39% | 4.11% |
| **1958** | 2.28% | 3.28% | 3.47% | 3.69% | 4.15% |
| **1959** | 4.90% | 5.03% | 4.94% | 5.10% | 5.08% |
| **1960** | 3.24% | 3.96% | 4.52% | 4.85% | 5.19% |
| **1961** | 2.84% | 3.59% | 4.38% | 4.61% | 5.05% |
| **1962** | 4.12% | 4.28% | 4.60% | 4.76% | 5.11% |
| **1963** | 3.61% | 4.21% | 4.48% | 4.77% | 5.09% |
| **1964** | 3.80% | 4.41% | 4.72% | 4.92% | 5.18% |
| **1965** | 4.04% | 4.52% | 4.90% | 5.09% | 5.21% |
| **1966** | 5.09% | 5.38% | 5.55% | 5.74% | 5.69% |
| **1967** | 4.72% | 5.29% | 5.64% | 5.94% | 5.94% |
| **1968** | 6.42% | 6.37% | 6.68% | 6.85% | 6.75% |
| **1969** | 7.39% | 7.49% | 7.66% | 7.76% | 7.58% |
| **1970** | 6.13% | 6.57% | 7.11% | 7.58% | 7.91% |
| **1971** | 3.61% | 4.93% | 5.56% | 6.15% | 6.95% |
| **1972** | 3.61% | 5.54% | 6.26% | 6.74% | 7.23% |
| **1973** | 5.59% | 6.54% | 6.98% | 7.17% | 7.56% |
| **1974** | 8.06% | 8.03% | 8.12% | 8.27% | 8.90% |
| **1975** | 7.61% | 7.56% | 7.72% | 8.06% | 9.04% |
| **1976** | 9.17% | 8.27% | 8.35% | 8.73% | 9.18% |
| **1977** | 7.54% | 7.46% | 7.90% | 8.14% | 8.70% |
| **1978** | 8.97% | 8.77% | 9.00% | 9.08% | 9.27% |
| **1979** | 12.23% | 10.77% | 10.42% | 10.16% | 10.21% |
| **1980** | 13.45% | 12.44% | 12.37% | 12.30% | 12.48% |
| **1981** | 18.99% | 15.97% | 15.68% | 15.29% | 15.22% |
| **1982** | 14.41% | 13.95% | 14.00% | 14.03% | 14.26% |
| **1983** | 9.65% | 10.18% | 10.61% | 11.11% | 11.79% |
| **1984** | 11.54% | 11.67% | 11.91% | 12.42% | 12.75% |
| **1985** | 9.78% | 10.12% | 10.39% | 10.78% | 11.04% |
| **1986** | 9.29% | 9.09% | 9.21% | 9.37% | 9.52% |
| **1987** | 8.40% | 9.19% | 9.42% | 9.55% | 9.95% |
| **1988** | 9.83% | 9.67% | 9.77% | 9.76% | 10.22% |
| **1989** | 12.62% | 10.71% | 10.20% | 9.83% | 9.92% |
| **1990** | 13.45% | 11.65% | 11.19% | 10.82% | 10.85% |
| **1991** | 9.02% | 8.99% | 9.16% | 9.36% | 9.76% |
| **1992** | 6.76% | 7.03% | 7.43% | 8.16% | 8.77% |
| **1993** | 4.94% | 5.89% | 6.46% | 7.24% | 7.85% |
| **1994** | 5.66% | 7.14% | 7.79% | 8.26% | 8.63% |
| **1995** | 7.08% | 7.26% | 7.64% | 7.93% | 8.28% |
| **1996** | 4.28% | 5.35% | 6.21% | 6.86% | 7.50% |
| **1997** | 3.30% | 4.68% | 5.33% | 5.87% | 6.42% |
| **1998** | 4.82% | 5.09% | 5.16% | 5.26% | 5.47% |
| **1999** | 4.80% | 5.36% | 5.50% | 5.56% | 5.69% |
| **2000** | 5.61% | 5.91% | 5.99% | 5.96% | 5.89% |
| **2001** | 3.83% | 4.25% | 4.88% | 5.32% | 5.78% |
| **2002** | 2.61% | 3.55% | 4.44% | 5.08% | 5.66% |
| **2003** | 2.90% | 3.24% | 3.88% | 4.54% | 5.28% |
| **2004** | 2.24% | 2.92% | 3.67% | 4.34% | 5.08% |

Sources and Notes:

[1] - [5]: Report on Canadian Economic Statistics 1924-2004, March 2005; Table 4 - A.

Workpaper #2 to Table No. MJV-9

2005 Canadian Utilities Sample

Panel B: Calculation of Maturity Premia for Different Bond Series

| | Annual Historical Average | | | | | Maturity Premium Calculation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 91-Day T-Bill Total Return [1] | 1-3 Year Bond Yields [2] | 3-5 Year Bond Yields [3] | 5-10 Year Bond Yields [4] | Long-Term Government Bond Yield [5] | 91-Day T-Bill Total Return [6] | 1-3 Year Bond Yields [7] | 3-5 Year Bond Yields [8] | 5-10 Year Bond Yields [9] | Long-Term Government Bond Yield [10] |
| 1936 - 2004 | 5.01% | | | | 6.44% | 0.00% | | | | 1.43% |
| 1951 - 2004 | 6.25% | 6.56% | 6.86% | 7.10% | 7.40% | 0.00% | 0.31% | 0.61% | 0.85% | 1.15% |
| 1959 - 2004 | 7.00% | 7.18% | 7.47% | 7.73% | 8.06% | 0.00% | 0.18% | 0.47% | 0.73% | 1.06% |
| 1969 - 2004 | 7.75% | 7.87% | 8.15% | 8.41% | 8.79% | 0.00% | 0.11% | 0.39% | 0.66% | 1.04% |
| 1979 - 2004 | 8.13% | 8.16% | 8.41% | 8.66% | 9.01% | 0.00% | 0.02% | 0.28% | 0.53% | 0.88% |
| 1989 - 2004 | 5.87% | 6.19% | 6.56% | 6.90% | 7.30% | 0.00% | 0.32% | 0.69% | 1.03% | 1.43% |

Sources and Notes:

[1] - [5] : Workpaper #2 to Table No. MJV-9, Panel A.

The Average Historical Yields from 1936 - 2004 were not calculated for [2], [3] and [4] because a complete set of yields is not available.

The Maturity Premium is defined as the Average Bond Yield (for different series) - the Risk Free Total Return.

[6]: [1] - [1].

[7]: [2] - [1].

[8]: [3] - [1].

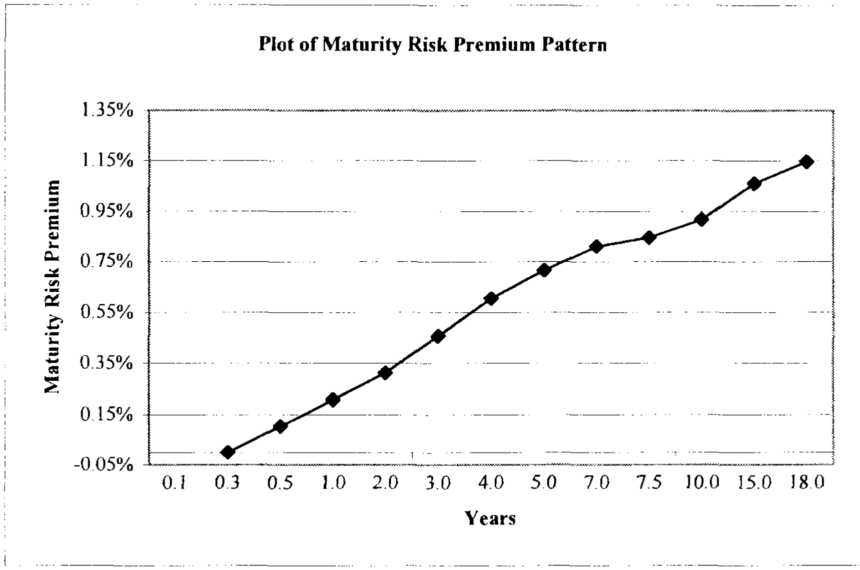
[9]: [4] - [1].

[10]: [5] - [1].

Workpaper #2 to Table No. MJV-9

2005 Canadian Utilities Sample

Panel C: Maturity Premium Graph and Calculations (Using Annual Series Data)




| Maturity of Bond (Years) [1] | Maturity Risk Premium [2] | Annualized Difference [3] |
|---|---|---|
| 0.083 | | |
| 0.25 | 0.00% | 0.0000 |
| 0.5 | 0.10% | 0.0041 |
| 1 | 0.21% | 0.0021 |
| 2 | 0.31% | 0.0010 |
| 3 | 0.46% | 0.0015 |
| 4 | 0.61% | 0.0015 |
| 5 | 0.72% | 0.0011 |
| 7 | 0.81% | 0.0005 |
| 7.5 | 0.85% | 0.0007 |
| 10 | 0.92% | 0.0003 |
| 15 | 1.06% | 0.0003 |
| 18 | 1.15% | 0.0003 |

Sources and Notes:

[1]: The maturity of a bond in years.

[2]: Workpaper #2 to Table No. MJV-5; Panel B; [6] - [10]. This is the Maturity Risk Premium in the graph.

[3]: The difference between the Maturity Risk Premium / The difference in the Maturity of the Bond.

Table No. MJV-10

Risk Positioning Cost of Equity of the 2005 Canadian Utilities Sample

Using Predicted Betas and the Long-Term Risk-Free Rate

| | Canadian Long-Term Risk-Free Rate [1] | Predicted Beta on Market [2] | Long-Term Market Risk Premium [3] | CAPM Cost of Equity [4] | ECAPM (1.0%) Cost of Equity [5] | ECAPM (2.0%) Cost of Equity [6] |
|---|---|---|---|---|---|---|
| Full Sample | 4.8% | 0.56 | 5.25% | 7.7% | 8.2% | 8.6% |
| Subsample | 4.8% | 0.57 | 5.25% | 7.8% | 8.2% | 8.7% |

Sources and Notes:
[1]: Consensus Forecast, January 9, 2006.
Sum of 10-Year Canadian Government Bond Forecast (4.6%) + Maturity Premium of 0.20%.
See Workpaper #2 to Table No. MJV-9, Panel C for maturity premium calculation.
[2]: Workpaper #1 to Table No. MJV-10.
[3]: Vilbert Written Evidence, Appendix B.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.0%) + [2] x ([3] - 1.0%).
[6]: ([1] + 2.0%) + [2] x ([3] - 2.0%).

## Workpaper #1 to Table No. MJV-10

## 2005 Canadian Utilities Sample

## Observed and Predicted Betas

| | Observed Beta<br>[1] | Predicted Beta<br>[2] |
|---|---|---|
| Full Sample | 0.47 | 0.56 |
| Subsample* | 0.66 | 0.57 |

Sources and Notes:
[1]: Workpaper #2 to Table No. MJV-10.
[2]: Vilbert Written Evidence.

Workpaper #2 to Table No. MJV-10

2005 Canadian Utilities Sample

52-Week Regression Statistics for Week Ending on 12/21/2005

| Company | Canadian Utilities | Emera Inc | Enbridge Inc | Transcanada Corp | Fortis Inc | Gaz Metro L.P. | Average |
|---|---|---|---|---|---|---|---|
| Beta | 0.64 | 0.06 | 0.80 | 0.53 | 0.57 | 0.24 | **0.47** |
| T-Stat | 2.76 | 0.37 | 4.11 | 3.33 | 2.50 | 1.14 | **2.37** |

Sources and Notes:
Compustat as of January 2006.
Risk-free rate taken from the 1-Month T-Bill from Bank of Canada.
Regression in Question:
(Company Returns - Risk-Free Rate) = Intercept + Beta (TSX Returns - Risk-Free Rate).
Weekly data set is constructed using closing prices as of Wednesday, if available. If not available, Tuesday's closing price was used.

Table No. MJV-11

Overall Cost of Capital of the 2005 Canadian Utilities Sample

Panel A: CAPM Cost of Equity Based on Predicted Betas and a Long-Term Risk-Free Rate

| | CAPM Cost of Equity [1] | 52-Week Average Common Equity to Market Value Ratio [2] | Average Cost of Preferred Equity [3] | 52-Week Average Preferred Equity to Market Value Ratio [4] | Average Cost of Debt [5] | 52-Week Average Debt to Market Value Ratio [6] | Union's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|
| Full Sample | 7.7% | 0.53 | 5.04% | 0.02 | 5.04% | 0.44 | 36.1% | 5.7% |
| Subsample* | 7.8% | 0.55 | 4.90% | 0.03 | 4.90% | 0.43 | 36.1% | 5.7% |

Sources and Notes:

[1]: Table No. MJV-10, [4].

[2]: Workpaper #4 to Table No. MJV-4, [2].

[3]: Workpaper #3 to Table No. MJV-11, Panel B, [3].

[4]: Workpaper #4 to Table No. MJV-4, [3].

[5]: Workpaper #3 to Table No. MJV-11, Panel A, [3].

[6]: Workpaper #4 to Table No. MJV-4, [4].

[7]: Provided by Union.

[8]: [1] x [2] + [3] x [4] + [5] x [6] x (1 - [7]) .

Table No. MJV-11

Overall Cost of Capital of the 2005 Canadian Utilities Sample

Panel B: ECAPM (1.0%) Cost of Equity Based on Predicted Betas and a Long-Term Risk-Free Rate

| | ECAPM (1.0%) Cost of Equity [1] | 52-Week Average Common Equity to Market Value Ratio [2] | Average Cost of Preferred Equity [3] | 52-Week Average Preferred Equity to Market Value Ratio [4] | Average Cost of Debt [5] | 52-Week Average Debt to Market Value Ratio [6] | Union's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|
| Full Sample | 8.2% | 0.53 | 5.04% | 0.02 | 5.04% | 0.44 | 36.1% | 5.9% |
| Subsample* | 8.2% | 0.55 | 4.90% | 0.03 | 4.90% | 0.43 | 36.1% | 6.0% |

Sources and Notes:

[1]: Table No. MJV-10, [5].

[2]: Workpaper #4 to Table No. MJV-4, [2].

[3]: Workpaper #3 to Table No. MJV-11, Panel B, [3].

[4]: Workpaper #4 to Table No. MJV-4, [3].

[5]: Workpaper #3 to Table No. MJV-11, Panel A, [3].

[6]: Workpaper #4 to Table No. MJV-4, [4].

[7]: Provided by Union.

[8]: [1] x [2] + [3] x [4] + [5] x [6] x (1 - [7]) .

Table No. MJV-11

Overall Cost of Capital of the 2005 Canadian Utilities Sample

Panel C: ECAPM (2.0%) Cost of Equity Based on Predicted Betas and a Long-Term Risk-Free Rate

| | ECAPM (2.0%) Cost of Equity [1] | 52-Week Average Common Equity to Market Value Ratio [2] | Average Cost of Preferred Equity [3] | 52-Week Average Preferred Equity to Market Value Ratio [4] | Average Cost of Debt [5] | 52-Week Average Debt to Market Value Ratio [6] | Union's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|
| Full Sample | 8.6% | 0.53 | 5.04% | 0.02 | 5.04% | 0.44 | 36.1% | 6.2% |
| Subsample* | 8.7% | 0.55 | 4.90% | 0.03 | 4.90% | 0.43 | 36.1% | 6.2% |

Sources and Notes:

[1]: Table No. MJV-10, [6].

[2]: Workpaper #4 to Table No. MJV-4, [2].

[3]: Workpaper #3 to Table No. MJV-11, Panel B, [3].

[4]: Workpaper #4 to Table No. MJV-4, [3].

[5]: Workpaper #3 to Table No. MJV-11, Panel A, [3].

[6]: Workpaper #4 to Table No. MJV-4, [4].

[7]: Provided by Union.

[8]: [1] x [2] + [3] x [4] + [5] x [6] x (1 - [7]) .

Workpaper #1 To Table No. MJV-11

Risk Positioning Cost of Equity of the 2005 Canadian Utilities Sample

Using 52-Week Observed Betas and the Long-Term Risk-Free Rate

| Company | | Canadian Long-Term Risk-Free Rate [1] | Observed Beta on Market [2] | Long-Term Market Risk Premium [3] | CAPM Cost of Equity [4] | ECAPM (1.0%) Cost of Equity [5] | ECAPM (2.0%) Cost of Equity [6] |
|---|---|---|---|---|---|---|---|
| Canadian Utilities | * | 4.8% | 0.64 | 5.25% | 8.2% | 8.5% | 8.9% |
| Emera Inc | | 4.8% | 0.06 | 5.25% | 5.1% | 6.1% | 7.0% |
| Enbridge Inc | * | 4.8% | 0.80 | 5.25% | 9.0% | 9.2% | 9.4% |
| Transcanada Corp | * | 4.8% | 0.53 | 5.25% | 7.6% | 8.0% | 8.5% |
| Fortis Inc | | 4.8% | 0.57 | 5.25% | 7.8% | 8.2% | 8.7% |
| Gaz Metro L.P. | | 4.8% | 0.24 | 5.25% | 6.0% | 6.8% | 7.6% |

Sources and Notes:

[1]: Consensus Forecast, January 9, 2006.
Sum of 10-Year Canadian Government Bond Forecast (4.6%) + Maturity Premium of 0.20%.
See Workpaper #2 to Table No. MJV-9, Panel C for maturity premium calculation.

[2]: Workpaper #2 to Table No. MJV-10.

[3]: Vilbert Written Evidence, Appendix B.

[4]: [1] + ([2] x [3]).

[5]: ([1] + 1.0%) + [2] x ([3] - 1.0%).

[6]: ([1] + 2.0%) + [2] x ([3] - 2.0%).

* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years and a Cost of Equity greater than Cost of Debt plus 25 bps.

## Workpaper #2 to Table No. MJV-11

## 2005 Canadian Utilities Sample

### Panel A: Bond Rating Summary

| Company | Bond Rating [1] |
|---|---|
| Canadian Utilities | A |
| Emera Inc | BBB |
| Enbridge Inc | A |
| Transcanada Corp | A |
| Fortis Inc | BBB |
| Gaz Metro L.P. | A |

Sources and Notes:
[1]: Dominion Bond Rating Service, www.dbrs.com, as of January 23, 2006.
Ratings are for Unsecured Debentures except for Emera (Medium Term Notes) and Gaz Metro L.P. (First Mortgage Bonds and Other Secured Debt).

## Workpaper #2 to Table No. MJV-11

## 2005 Canadian Utilities Sample

### Panel B: Preferred Stock Rating Summary

| Company | Preferred Rating [1] |
|---|---|
| Canadian Utilities | A |
| Emera Inc | - |
| Enbridge Inc | A |
| Transcanada Corp | - |
| Fortis Inc | BBB |
| Gaz Metro L.P. | - |

Sources and Notes:

[1]: Preferred equity ratings are assumed equal to the company's bond rating reported in Workpaper #2 to Table No. MJV-11, Panel A.

## Workpaper #3 to Table No. MJV-11

## 2005 Canadian Utilities Sample

## Panel A: Bond Yield Summary

| Company | | Bond Yield<br>[1] |
|---|---|---|
| Canadian Utilities | * | 4.90% |
| Emera Inc | (*) | 5.31% |
| Enbridge Inc | * | 4.90% |
| Transcanada Corp | * | 4.90% |
| Fortis Inc | | 5.31% |
| Gaz Metro L.P. | | 4.90% |
| Full Sample | | 5.04% |
| Subsample* | | 4.90% |

Sources and Notes:
[1]: Ratings based on Workpaper #2 to Table No. MJV-11, Panel A and
bond yields from CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005.
* Companies marked with an asterisk represent those with no mergers and acquisitions or
dividend cuts for five years.
Emera is included in the DCF, but is excluded from the CAPM and ECAPM because
CoE is less than CoD plus 25 bps.
In this subsample average, Emera is excluded.

Workpaper #3 to Table No. MJV-11

2005 Canadian Utilities Sample

Panel B: Preferred Stock Yield Summary

| Company | | Preferred Yields [1] |
|---|---|---|
| Canadian Utilities | * | 4.90% |
| Emera Inc | (*) | - |
| Enbridge Inc | * | 4.90% |
| Transcanada Corp | * | - |
| Fortis Inc | | 5.31% |
| Gaz Metro L.P. | | - |
| Full Sample | | 5.04% |
| Subsample* | | 4.90% |

Sources and Notes:

[1] - [2]: Ratings based on Workpaper #2 to Table No. MJV-11, Panel A.
Preferred stock yields are assumed equal to the bond yields.

* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.

Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than CoD plus 25 bps.
In this subsample average, Emera is excluded.

Workpaper #4 to Table No. MJV-11

2005 Canadian Utilities Sample

Bond Yield Inputs

| Public Utility Bonds | |
| --- | --- |
| A | BBB |
| 4.90% | 5.31% |

Sources and Notes:
CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005.

Table No. MJV-12

Capital Structure Consistent with 2005 Canadian Utilities Sample Information

**Panel A: Using Union's Allowed ROE: 9.63%**

Using All Companies

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| ***Using Long-Term Risk-Free Rates:*** | | | | | | | | |
| CAPM using Predicted Betas | 5.7% | 57.5% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 39.3% |
| ECAPM (1.00%) using Predicted Betas | 5.9% | 53.9% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 42.9% |
| ECAPM (2.00%) using Predicted Betas | 6.2% | 50.3% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 46.5% |

Sources and Notes:

[1]: Table No. MJV-11, Panels A - C, [8].

[2]: 1 - [5] - [8].

[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

Table No. MJV-12

Capital Structure Consistent with 2005 Canadian Utilities Sample Information

**Panel B: Using Union's Estimated ROE for 2006: 8.89%**

Using All Companies

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free Rates:** | | | | | | | | |
| CAPM using Predicted Betas | 5.7% | 52.4% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 44.4% |
| ECAPM (1.00%) using Predicted Betas | 5.9% | 48.4% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 48.4% |
| ECAPM (2.00%) using Predicted Betas | 6.2% | 44.3% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 52.5% |

Sources and Notes:

[1]: Table No. MJV-11, Panels A - C, [8].

[2]: 1 - [5] - [8].

[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

Table No. MJV-12

Capital Structure Consistent with 2005 Canadian Utilities Sample Information

**Panel C: Using Union's Allowed ROE: 9.63%**

Using Subsample

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free Rates:** | | | | | | | | |
| CAPM using Predicted Betas | 5.7% | 56.7% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 40.1% |
| ECAPM (1.00%) using Predicted Betas | 6.0% | 53.1% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 43.7% |
| ECAPM (2.00%) using Predicted Betas | 6.2% | 49.5% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 47.3% |

Sources and Notes:

[1]: Table No. MJV-11, Panels A - C, [8].

[2]: 1 - [5] - [8].

[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.

Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps. .

See Workpaper #1 To Table No. MJV-11.

Table No. MJV-12

Capital Structure Consistent with 2005 Canadian Utilities Sample Information

**Panel D: Using Union's Estimated ROE for 2006: 8.89%**

Using Subsample

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free Rates:** | | | | | | | | |
| CAPM using Predicted Betas | 5.7% | 51.5% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 45.2% |
| ECAPM (1.00%) using Predicted Betas | 6.0% | 47.5% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 49.3% |
| ECAPM (2.00%) using Predicted Betas | 6.2% | 43.4% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 53.4% |

Sources and Notes:

[1]: Table No. MJV-11, Panels A - C, [8].

[2]: 1 - [5] - [8].

[3]: CIBC World Markets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating from Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4]) } / {[7] - [3] x (1 - [4])}.

* Companies marked with an asterisk represent those with no mergers and acquisitions or dividend cuts for five years.

Emera is included in the DCF, but is excluded from the CAPM and ECAPM because CoE is less than than CoD plus 25 bps.

See Workpaper #1 To Table No. MJV-11.

Table No. MJV-13

2005 US LDC Sample

Percentage of Revenue from Regulated Activity in 2004
(US$ MM)

| Company | | Regulated Segment Description [1] | Revenues from Regulated Actvities [2] | Revenues from Unregulated Actvities [3] | Total Revenues [4] | Percentage from Regulated Activities [5] |
|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | All Segments | 318.08 | 0.00 | 318.08 | 100.00% |
| Keyspan Corp | | Gas Distribution | 4,407.29 | 2,243.17 | 6,650.47 | 66.27% |
| Laclede Group Inc | * | Regulated Gas Distribution | 868.91 | 2.58 | 871.48 | 99.70% |
| Northwest Natural Gas Co | * | Utility | 301.77 | 6.59 | 308.36 | 97.86% |
| Peoples Energy Corp | | Gas Distribution | 1,494.46 | 765.74 | 2,260.20 | 66.12% |
| South Jersey Industries Inc | | Gas Utility Operations | 502.47 | 316.61 | 819.08 | 61.35% |
| Southwest Gas Corp | * | Gas Operating Revenues | 1,262.05 | 215.01 | 1,477.06 | 85.44% |
| Wgl Holdings Inc | | Regulated Utility | 1,293.68 | 795.93 | 2,089.60 | 61.91% |
| Average [a] | | | | | | 79.83% |
| Average [b] | | | | | | 95.75% |

Sources and Notes:
[1], [2] and [4]: Company Form 10-K's for 2004.
[3]: [4] - [2].
[5]: [2] / [4].

[a]: Average over all companies.
[b]: Average for companies marked with an asterisk.
* Represents companies that have revenues from regulated activities greater than 70%.

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel A: Cascade Natural Gas Corp

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $119 | $119 | $123 | $119 | $118 | $125 | $125 | [a] |
| Shares Outstanding (in millions) - Common | 11 | 11 | 11 | 11 | 11 | 11 | 11 | [b] |
| Price per Share - Common | $20.19 | $21.56 | $21.31 | $21.47 | $20.07 | $21.74 | $19.99 | [c] |
| Market Value of Common Equity | $230 | $246 | $241 | $240 | $222 | $240 | $221 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.94 | 2.07 | 1.96 | 2.02 | 1.88 | 1.92 | 1.77 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $142 | $142 | $86 | $67 | $62 | $67 | $72 | [h] |
| Current Liabilities | $142 | $142 | $116 | $83 | $50 | $60 | $76 | [i] |
| Current Portion of Long-Term Debt | $14 | $14 | $14 | $22 | $0 | $0 | $0 | [j] |
| Net Working Capital | $14 | $14 | ($16) | $6 | $12 | $7 | ($4) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $34 | $34 | $34 | $4 | $0 | $40 | $2 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | $16 | $0 | $0 | $0 | $2 | [m] = See Sources and Notes. |
| Long-Term Debt | $174 | $174 | $129 | $139 | $165 | $165 | $125 | [n] |
| Book Value of Long-Term Debt | $188 | $188 | $143 | $161 | $165 | $165 | $125 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $188 | $188 | $143 | $161 | $165 | $165 | $125 | [p] = [o]. |
| Market Value of Debt | $188 | $188 | $158 | $161 | $165 | $165 | $127 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $418 | $434 | $399 | $401 | $387 | $405 | $347 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 55.09% | 56.70% | 60.29% | 59.86% | 57.34% | 59.28% | 63.57% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | - | - | - | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 44.91% | 43.30% | 39.71% | 40.14% | 42.66% | 40.72% | 36.43% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Cascade Natural Gas Corp did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel B: Keyspan Corp

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $4,388 | $4,388 | $3,895 | $3,662 | $2,945 | $2,891 | $2,816 | [a] |
| Shares Outstanding (in millions) - Common | 174 | 174 | 161 | 160 | 142 | 139 | 136 | [b] |
| Price per Share - Common | $33.94 | $36.88 | $39.44 | $36.77 | $35.21 | $34.64 | $42.13 | [c] |
| Market Value of Common Equity | $5,918 | $6,430 | $6,342 | $5,871 | $5,014 | $4,830 | $5,744 | [d] = [b] x [c] |
| Market to Book Value of Common Equity | 1.35 | 1.47 | 1.63 | 1.60 | 1.70 | 1.67 | 2.04 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $20 | $84 | $84 | $84 | $84 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $20 | $84 | $84 | $84 | $84 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $2,953 | $2,953 | $3,079 | $2,387 | $2,216 | $1,998 | $2,403 | [h] |
| Current Liabilities | $1,709 | $1,709 | $2,282 | $1,849 | $2,220 | $2,385 | $2,974 | [i] |
| Current Portion of Long-Term Debt | $16 | $16 | $16 | $1 | $11 | $1 | $5 | [j] |
| Net Working Capital | $1,261 | $1,261 | $812 | $540 | $8 | ($385) | ($565) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $912 | $912 | $912 | $482 | $916 | $1,048 | $1,300 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | $0 | $0 | $0 | $385 | $565 | [m] = See Sources and Notes. |
| Long-Term Debt | $3,915 | $3,915 | $4,419 | $5,611 | $5,224 | $4,698 | $4,275 | [n] |
| Book Value of Long-Term Debt | $3,931 | $3,931 | $4,435 | $5,613 | $5,235 | $4,699 | $4,280 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $3,931 | $3,931 | $4,435 | $5,613 | $5,235 | $4,699 | $4,280 | [p] = [o]. |
| Market Value of Debt | $3,931 | $3,931 | $4,435 | $5,613 | $5,235 | $5,084 | $4,846 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $9,848 | $10,361 | $10,797 | $11,568 | $10,334 | $9,998 | $10,674 | [r] = [d] + [g] + [q]. |
| ***DEBT AND EQUITY TO MARKET VALUE RATIOS*** | | | | | | | | |
| Common Equity - Market Value Ratio | 60.09% | 62.06% | 58.74% | 50.76% | 48.52% | 48.31% | 53.81% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | 0.18% | 0.72% | 0.81% | 0.84% | 0.79% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 39.91% | 37.94% | 41.08% | 48.52% | 50.66% | 50.85% | 45.40% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Keyspan Corp did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel C: Laclede Group Inc

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $367 | $367 | $369 | $309 | $295 | $289 | $295 | [a] |
| Shares Outstanding (in millions) - Common | 21 | 21 | 21 | 19 | 19 | 19 | 19 | [b] |
| Price per Share - Common | $29.51 | $32.45 | $31.19 | $29.32 | $24.20 | $23.78 | $23.85 | [c] |
| Market Value of Common Equity | $625 | $687 | $656 | $561 | $459 | $449 | $450 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.70 | 1.87 | 1.78 | 1.81 | 1.55 | 1.55 | 1.53 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $1 | $1 | $1 | $1 | $1 | $1 | $2 | [f] |
| Market Value of Preferred Equity | $1 | $1 | $1 | $1 | $1 | $1 | $2 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $424 | $424 | $465 | $378 | $300 | $242 | $349 | [h] |
| Current Liabilities | $366 | $366 | $401 | $455 | $360 | $262 | $363 | [i] |
| Current Portion of Long-Term Debt | $25 | $25 | $25 | $0 | $25 | $0 | $0 | [j] |
| Net Working Capital | $84 | $84 | $89 | ($77) | ($35) | ($19) | ($14) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $71 | $71 | $71 | $218 | $162 | $117 | $127 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | $0 | $77 | $35 | $19 | $14 | [m] = See Sources and Notes. |
| Long-Term Debt | $340 | $340 | $380 | $280 | $305 | $284 | $234 | [n] |
| Book Value of Long-Term Debt | $366 | $366 | $406 | $280 | $330 | $284 | $234 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $366 | $366 | $406 | $280 | $330 | $284 | $234 | [p] = [o]. |
| *Market Value of Debt* | $366 | $366 | $406 | $357 | $365 | $304 | $249 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $991 | $1,053 | $1,062 | $919 | $825 | $754 | $701 | [r] = [d] + [g] + [q] |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 63.02% | 65.21% | 61.73% | 61.01% | 55.64% | 59.53% | 64.24% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | 0.10% | 0.09% | 0.10% | 0.14% | 0.15% | 0.17% | 0.25% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 36.88% | 34.70% | 38.17% | 38.86% | 44.21% | 40.30% | 35.51% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

*The DCF Capital structure is calculated using 3rd Quarter,* 2005 balance sheet *information* and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Laclede Group Inc did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel D: Northwest Natural Gas Co

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $571 | $571 | $569 | $506 | $483 | $468 | $452 | [a] |
| Shares Outstanding (in millions) - Common | 28 | 28 | 28 | 26 | 26 | 25 | 25 | [b] |
| Price per Share - Common | $34.76 | $37.01 | $33.68 | $31.01 | $27.18 | $25.79 | $26.79 | [c] |
| Market Value of Common Equity | $958 | $1,019 | $928 | $804 | $695 | $651 | $676 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.68 | 1.79 | 1.63 | 1.59 | 1.44 | 1.39 | 1.49 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $0 | $0 | $8 | $34 | $35 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $0 | $0 | $8 | $34 | $35 | [g] = [f] |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $205 | $205 | $237 | $200 | $194 | $210 | $187 | [h] |
| Current Liabilities | $218 | $218 | $267 | $214 | $205 | $274 | $221 | [i] |
| Current Portion of Long-Term Debt | $15 | $15 | $15 | $0 | $20 | $40 | $20 | [j] |
| Net Working Capital | $2 | $2 | ($15) | ($15) | $9 | ($23) | ($14) | [k] = [h] - ([i] - [j]). |
| *Notes Payable (Short-Term Debt)* | $103 | $103 | $103 | $85 | $70 | $108 | $56 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | $15 | $15 | $0 | $23 | $14 | [m] = See Sources and Notes. |
| Long-Term Debt | $522 | $522 | $484 | $500 | $446 | $378 | $401 | [n] |
| Book Value of Long-Term Debt | $537 | $537 | $499 | $500 | $466 | $418 | $421 | [o] = [n] + [j] |
| Market Value of Long-Term Debt | $537 | $537 | $499 | $500 | $466 | $418 | $421 | [p] = [o] |
| Market Value of Debt | $537 | $537 | $514 | $515 | $466 | $442 | $435 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $1,494 | $1,556 | $1,442 | $1,319 | $1,170 | $1,126 | $1,145 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 64.09% | 65.52% | 64.34% | 60.95% | 59.46% | 57.77% | 59.01% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | - | - | 0.71% | 3.02% | 3.03% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 35.91% | 34.48% | 35.66% | 39.05% | 39.84% | 39.21% | 37.96% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

*Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.*

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Northwest Natural Gas Co did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel E: Peoples Energy Corp

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $800 | $800 | $884 | $863 | $815 | $809 | $766 | [a] |
| Shares Outstanding (in millions) - Common | 38 | 38 | 38 | 37 | 36 | 35 | 35 | [b] |
| Price per Share ($) - Common | $36.76 | $39.25 | $44.28 | $42.02 | $38.55 | $38.18 | $45.11 | [c] |
| Market Value of Common Equity | $1,402 | $1,498 | $1,677 | $1,554 | $1,371 | $1,353 | $1,596 | [d] = [b] x [c] |
| Market to Book Value of Common Equity | 1.75 | 1.87 | 1.90 | 1.80 | 1.68 | 1.67 | 2.08 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $899 | $899 | $801 | $702 | $581 | $562 | $927 | [h] |
| Current Liabilities | $902 | $902 | $715 | $744 | $998 | $797 | $1,308 | [i] |
| Current Portion of Long-Term Debt | $0 | $0 | $0 | $0 | $90 | $100 | $0 | [j] |
| Net Working Capital | ($3) | ($3) | $85 | ($42) | ($327) | ($135) | ($381) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $56 | $56 | $56 | $208 | $288 | $507 | $568 | [l] |
| Adjusted Short-Term Debt | $3 | $3 | $0 | $42 | $288 | $135 | $381 | [m] = See Sources and Notes. |
| Long-Term Debt | $896 | $896 | $897 | $846 | $529 | $644 | $419 | [n] |
| Book Value of Long-Term Debt | $896 | $896 | $897 | $846 | $619 | $744 | $419 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $896 | $896 | $897 | $846 | $619 | $744 | $419 | [p] = [o] |
| Market Value of Debt | $899 | $899 | $897 | $889 | $907 | $879 | $800 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $2,301 | $2,396 | $2,574 | $2,443 | $2,278 | $2,233 | $2,396 | [r] = [d] + [g] + [q] |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 60.95% | 62.50% | 65.14% | 63.62% | 60.18% | 60.61% | 66.61% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | - | - | - | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 39.05% | 37.50% | 34.86% | 36.38% | 39.82% | 39.39% | 33.39% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Peoples Energy Corp did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel F: South Jersey Industries Inc

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $368 | $368 | $344 | $298 | $238 | $220 | $202 | [a] |
| Shares Outstanding (in millions) - Common | 28 | 28 | 28 | 26 | 24 | 24 | 23 | [b] |
| Price per Share ($) - Common | $29.44 | $29.04 | $26.23 | $20.21 | $16.53 | $16.54 | $14.72 | [c] |
| Market Value of Common Equity | $837 | 825.26 | 728.14 | 534.66 | 403.53 | 392.46 | 338.53 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 2.27 | 2.24 | 2.11 | 1.79 | 1.70 | 1.78 | 1.68 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $2 | $2 | $2 | $2 | $2 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $2 | $2 | $2 | $2 | $2 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $294 | $294 | $284 | $266 | $213 | $222 | $175 | [h] |
| Current Liabilities | $324 | $324 | $285 | $268 | $317 | $310 | $257 | [i] |
| Current Portion of Long-Term Debt | $5 | $5 | $5 | $5 | $11 | $10 | $12 | [j] |
| Net Working Capital | ($24) | ($24) | $4 | $3 | ($93) | ($78) | ($70) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $92 | $92 | $92 | $113 | $167 | $152 | $121 | [l] |
| Adjusted Short-Term Debt | $24 | $24 | $0 | $0 | $93 | $78 | $70 | [m] = See Sources and Notes. |
| Long-Term Debt | $319 | $319 | $329 | $309 | $273 | $294 | $240 | [n] |
| Book Value of Long-Term Debt | $324 | $324 | $334 | $314 | $284 | $304 | $252 | [o] = [n] + [j] |
| Market Value of Long-Term Debt | $324 | $324 | $334 | $314 | $284 | $304 | $252 | [p] = [o] |
| Market Value of Debt | $349 | $349 | $334 | $314 | $377 | $382 | $322 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $1,185 | $1,174 | $1,064 | $850 | $782 | $776 | $663 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 70.59% | 70.31% | 68.43% | 62.87% | 51.59% | 50.54% | 51.10% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | 0.16% | 0.20% | 0.22% | 0.22% | 0.27% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 29.41% | 29.69% | 31.41% | 36.93% | 48.19% | 49.24% | 48.63% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: South Jersey Industries Inc did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l]

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel G: Southwest Gas Corp

*(US$ MM)*

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $751 | $751 | $706 | $630 | $596 | $561 | $533 | [a] |
| Shares Outstanding (in millions) - Common | 39 | 39 | 37 | 34 | 33 | 32 | 32 | [b] |
| Price per Share ($) - Common | $26.81 | $27.44 | $25.49 | $22.89 | $23.14 | $22.69 | $21.91 | [c] |
| Market Value of Common Equity | $1,046 | $1,071 | $938 | $784 | $770 | $737 | $695 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.39 | 1.43 | 1.33 | 1.24 | 1.29 | 1.31 | 1.30 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [f] |
| Market Value of Preferred Equity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $298 | $298 | $432 | $281 | $262 | $400 | $403 | [h] |
| Current Liabilities | $390 | $390 | $483 | $310 | $313 | $653 | $482 | [i] |
| Current Portion of Long-Term Debt | $30 | $30 | $30 | $6 | $9 | $308 | $8 | [j] |
| Net Working Capital | ($62) | ($62) | ($21) | ($23) | ($43) | $55 | ($70) | [k] = [h] - ([i] - [j]). |
| Notes Payable (Short-Term Debt) | $100 | $100 | $100 | $52 | $53 | $93 | $131 | [l] |
| Adjusted Short-Term Debt | $62 | $62 | $21 | $23 | $43 | $0 | $70 | [m] = See Sources and Notes. |
| Long-Term Debt | $1,249 | $1,249 | $1,263 | $1,221 | $1,152 | $856 | $956 | [n] |
| Book Value of Long-Term Debt | $1,279 | $1,279 | $1,293 | $1,228 | $1,161 | $1,164 | $965 | [o] = [n] + [j] |
| Market Value of Long-Term Debt | $1,279 | $1,279 | $1,293 | $1,228 | $1,161 | $1,164 | $965 | [p] = [o] |
| Market Value of Debt | $1,341 | $1,341 | $1,314 | $1,250 | $1,204 | $1,164 | $1,035 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $2,388 | $2,413 | $2,252 | $2,034 | $1,974 | $1,901 | $1,730 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 43.82% | 44.40% | 41.65% | 38.53% | 39.03% | 38.78% | 40.17% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | - | - | - | - | - | - | - | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 56.18% | 55.60% | 58.35% | 61.47% | 60.97% | 61.22% | 59.83% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on *12/16/2005*.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Southwest Gas Corp did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-14

Market Value of the 2005 US LDC Sample

Panel H: Wgl Holdings Inc

(US$ MM)

| | DCF Capital Structure | 3rd Quarter, 2005 | Year End, 2004 | Year End, 2003 | Year End, 2002 | Year End, 2001 | Year End, 2000 | Notes |
|---|---|---|---|---|---|---|---|---|
| **MARKET VALUE OF COMMON EQUITY** | | | | | | | | |
| Book Value, Common Shareholder's Equity | $894 | $894 | $881 | $843 | $802 | $803 | $748 | [a] |
| Shares Outstanding (in millions) - Common | 49 | 49 | 49 | 49 | 49 | 49 | 46 | [b] |
| Price per Share ($) - Common | $30.59 | $32.00 | $31.01 | $28.11 | $24.01 | $29.22 | $30.59 | [c] |
| Market Value of Common Equity | $1,490 | $1,559 | $1,509 | $1,367 | $1,167 | $1,419 | $1,422 | [d] = [b] x [c]. |
| Market to Book Value of Common Equity | 1.67 | 1.74 | 1.71 | 1.62 | 1.45 | 1.77 | 1.90 | [e] = [d] / [a]. |
| **MARKET VALUE OF PREFERRED EQUITY** | | | | | | | | |
| Book Value of Preferred Equity | $28 | $28 | $28 | $28 | $28 | $28 | $28 | [f] |
| Market Value of Preferred Equity | $28 | $28 | $28 | $28 | $28 | $28 | $28 | [g] = [f]. |
| **MARKET VALUE OF DEBT** | | | | | | | | |
| Current Assets | $481 | $481 | $631 | $591 | $513 | $476 | $641 | [h] |
| Current Liabilities | $411 | $411 | $627 | $552 | $529 | $422 | $594 | [i] |
| Current Portion of Long-Term Debt | $61 | $61 | $61 | $12 | $42 | $48 | $2 | [j] |
| Net Working Capital | $130 | $130 | $65 | $51 | $26 | $102 | $48 | [k] = [h] - ([i] - [j]) |
| Notes Payable (Short-Term Debt) | $96 | $96 | $96 | $167 | $91 | $134 | $161 | [l] |
| Adjusted Short-Term Debt | $0 | $0 | $0 | $0 | $0 | $0 | $0 | [m] = See Sources and Notes. |
| Long-Term Debt | $584 | $584 | $574 | $638 | $623 | $613 | $578 | [n] |
| Book Value of Long-Term Debt | $645 | $645 | $634 | $650 | $666 | $661 | $579 | [o] = [n] + [j]. |
| Market Value of Long-Term Debt | $645 | $645 | $634 | $650 | $666 | $661 | $579 | [p] = [o]. |
| Market Value of Debt | $645 | $645 | $634 | $650 | $666 | $661 | $579 | [q] = [p] + [m]. |
| **MARKET VALUE OF FIRM** | $2,163 | $2,231 | $2,172 | $2,045 | $1,860 | $2,108 | $2,029 | [r] = [d] + [g] + [q]. |
| **DEBT AND EQUITY TO MARKET VALUE RATIOS** | | | | | | | | |
| Common Equity - Market Value Ratio | 68.89% | 69.84% | 69.49% | 66.85% | 62.71% | 67.30% | 70.06% | [s] = [d] / [r]. |
| Preferred Equity - Market Value Ratio | 1.30% | 1.26% | 1.30% | 1.38% | 1.51% | 1.34% | 1.39% | [t] = [g] / [r]. |
| Debt - Market Value Ratio | 29.81% | 28.89% | 29.21% | 31.78% | 35.78% | 31.36% | 28.56% | [u] = [q] / [r]. |

Sources and Notes:

Compustat as of December 27, 2005.

Capital structure from Year End, 2000 to 3rd Quarter, 2005 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2005 balance sheet information and a 15-trading day average closing price ending on 12/16/2005.

Prices are reported in Workpaper #1 to Table No. MJV-17.

[j] and [l]: Wgl Holdings Inc did not report their Current portion of Long-Term Debt and their Notes Payable for Q3, 2005 (DCF Capital Structure). The numbers are set to those for 2004.

[m] =

(1): 0 if [k] > 0

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

Table No. MJV-15

2005 US LDC Sample

Capital Structure Summary

| | | DCF Capital Structure | | | 5-Year Average Capital Structure | | |
|---|---|---|---|---|---|---|---|
| Company | | Common Equity - Value Ratio [1] | Preferred Equity - Value Ratio [2] | Debt - Value Ratio [3] | Common Equity - Value Ratio [4] | Preferred Equity - Value Ratio [5] | Debt - Value Ratio [6] |
| Cascade Natural Gas Corp | * | 0.55 | - | 0.45 | 0.59 | - | 0.41 |
| Keyspan Corp | | 0.60 | - | 0.40 | 0.53 | 0.01 | 0.46 |
| Laclede Group Inc | * | 0.63 | 0.00 | 0.37 | 0.61 | 0.00 | 0.39 |
| Northwest Natural Gas Co | * | 0.64 | - | 0.36 | 0.61 | 0.01 | 0.38 |
| Peoples Energy Corp | | 0.61 | - | 0.39 | 0.63 | - | 0.37 |
| South Jersey Industries Inc | | 0.71 | - | 0.29 | 0.60 | 0.00 | 0.40 |
| Southwest Gas Corp | * | 0.44 | - | 0.56 | 0.40 | - | 0.60 |
| Wgl Holdings Inc | | 0.69 | 0.01 | 0.30 | 0.67 | 0.01 | 0.31 |
| Average [a] | | 0.61 | 0.00 | 0.39 | 0.58 | 0.00 | 0.42 |
| Average [b] | | 0.57 | 0.00 | 0.43 | 0.55 | 0.00 | 0.44 |

Sources and Notes:
[1], [4]:Workpaper #1 to Table No. MJV-15.
[2], [5]:Workpaper #2 to Table No. MJV-15.
[3], [6]:Workpaper #3 to Table No. MJV-15.
Values in this table may not add up to one because of rounding.

[a]: Average over all companies.
[b]: Average for companies marked with an asterisk.
* Represents companies that have revenues from regulated activities greater than 70%.

Workpaper #1 to Table No. MJV-15

2005 US LDC Sample

Calculation of the Average Common Equity - Market Value Ratio from 2000 to 3rd Quarter, 2005

| Company | DCF Capital Structure [1] | 3rd Quarter, 2005 [2] | 2004 [3] | 2003 [4] | 2002 [5] | 2001 [6] | 2000 [7] | 5-Year Average [8] |
|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | 0.55 | 0.57 | 0.60 | 0.60 | 0.57 | 0.59 | 0.64 | 0.59 |
| Keyspan Corp | 0.60 | 0.62 | 0.59 | 0.51 | 0.49 | 0.48 | 0.54 | 0.53 |
| Laclede Group Inc | 0.63 | 0.65 | 0.62 | 0.61 | 0.56 | 0.60 | 0.64 | 0.61 |
| Northwest Natural Gas Co | 0.64 | 0.66 | 0.64 | 0.61 | 0.59 | 0.58 | 0.59 | 0.61 |
| Peoples Energy Corp | 0.61 | 0.63 | 0.65 | 0.64 | 0.60 | 0.61 | 0.67 | 0.63 |
| South Jersey Industries Inc | 0.71 | 0.70 | 0.68 | 0.63 | 0.52 | 0.51 | 0.51 | 0.60 |
| Southwest Gas Corp | 0.44 | 0.44 | 0.42 | 0.39 | 0.39 | 0.39 | 0.40 | 0.40 |
| Wgl Holdings Inc | 0.69 | 0.70 | 0.69 | 0.67 | 0.63 | 0.67 | 0.70 | 0.67 |

Sources and Notes:

[1] - [7]: Table No. MJV-14; Panels A - H, [s].

[8]: {[2] x 0.75 + [3] + [4] + [5] + [6]+ [7] x 0.25}/ 5.

Workpaper #2 to Table No. MJV-15

2005 US LDC Sample

Calculation of the Average Preferred Equity - Market Value Ratio from 2000 to 3rd Quarter, 2005

| Company | DCF Capital Structure [1] | 3rd Quarter, 2005 [2] | 2004 [3] | 2003 [4] | 2002 [5] | 2001 [6] | 2000 [7] | 5-Year Average [8] |
|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | - | - | - | - | - | - | - | - |
| Keyspan Corp | - | - | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Laclede Group Inc | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Northwest Natural Gas Co | - | - | - | - | 0.01 | 0.03 | 0.03 | 0.01 |
| Peoples Energy Corp | - | - | - | - | - | - | - | - |
| South Jersey Industries Inc | - | - | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Southwest Gas Corp | - | - | - | - | - | - | - | - |
| Wgl Holdings Inc | 0.01 | 0.01 | 0.01 | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 |

Sources and Notes:
[1] - [7]: Table No. MJV-14; Panels A - H, [t].
[8]: {[2] x 0.75 + [3] + [4] + [5] + [6]+ [7] x 0.25}/ 5.
Values reported as 0.00 have an insignificant amount of preferred equity.

Workpaper #3 to Table No. MJV-15

2005 US LDC Sample

Calculation of the Average Debt - Market Value Ratio from 2000 to 3rd Quarter, 2005

| Company | DCF Capital Structure<br>[1] | 3rd Quarter, 2005<br>[2] | 2004<br>[3] | 2003<br>[4] | 2002<br>[5] | 2001<br>[6] | 2000<br>[7] | 5-Year Average<br>[8] |
|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | 0.45 | 0.43 | 0.40 | 0.40 | 0.43 | 0.41 | 0.36 | 0.41 |
| Keyspan Corp | 0.40 | 0.38 | 0.41 | 0.49 | 0.51 | 0.51 | 0.45 | 0.46 |
| Laclede Group Inc | 0.37 | 0.35 | 0.38 | 0.39 | 0.44 | 0.40 | 0.36 | 0.39 |
| Northwest Natural Gas Co | 0.36 | 0.34 | 0.36 | 0.39 | 0.40 | 0.39 | 0.38 | 0.38 |
| Peoples Energy Corp | 0.39 | 0.37 | 0.35 | 0.36 | 0.40 | 0.39 | 0.33 | 0.37 |
| South Jersey Industries Inc | 0.29 | 0.30 | 0.31 | 0.37 | 0.48 | 0.49 | 0.49 | 0.40 |
| Southwest Gas Corp | 0.56 | 0.56 | 0.58 | 0.61 | 0.61 | 0.61 | 0.60 | 0.60 |
| Wgl Holdings Inc | 0.30 | 0.29 | 0.29 | 0.32 | 0.36 | 0.31 | 0.29 | 0.31 |

Sources and Notes:
[1] - [7]: Table No. MJV-14; Panels A - H, [u].
[8]: {[2] x 0.75 + [3] + [4] + [5] + [6]+ [7] x 0.25}/ 5.

Table No. MJV-16

2005 US LDC Sample

Combined I/B/E/S and Value Line Estimated Growth Rates

| Company | I/B/E/S | | Value Line | | | |
|---|---|---|---|---|---|---|
| | I/B/E/S Long-Term Growth Rate | Number of Estimates | Fiscal Year '06 EPS Estimate | Fiscal Year '08 to '10 EPS Estimate | Annualized Growth Rate | Combined I/B/E/S and Value Line Growth Rate |
| | [1] | [2] | [3] | [4] | [5] | [6] |
| Cascade Natural Gas Corp | 4.5% | 2 | $0.95 | $1.25 | 9.6% | 6.2% |
| Keyspan Corp | 3.5% | 5 | $2.50 | $3.10 | 7.4% | 4.2% |
| Laclede Group Inc | 5.0% | 1 | $2.00 | $2.30 | 4.8% | 4.9% |
| Northwest Natural Gas Co | 5.6% | 4 | $2.25 | $2.75 | 6.9% | 5.9% |
| Peoples Energy Corp | 4.5% | 3 | $2.40 | $3.10 | 8.9% | 5.6% |
| South Jersey Industries Inc | 6.0% | 1 | $2.00 | $2.20 | 3.2% | 4.6% |
| Southwest Gas Corp | 3.0% | 1 | $1.65 | $2.45 | 14.1% | 8.5% |
| Wgl Holdings Inc | 3.8% | 4 | $1.90 | $2.40 | 8.1% | 4.7% |

Sources and Notes:

[1], [2]: I/B/E/S Tearsheets as of December 16, 2005.

[3], [4]: Value Line Investment Survey, Standard Edition as of December 16, 2005.

[5]: ([4] / [3]) ^ (1/3) - 1.

[6]: ([1] x [2] + [5]) / ([2] + 1).

Table No. MJV-17

DCF Cost of Equity of the 2005 US LDC Sample

Panel A: Simple DCF Method (Quarterly)

| Company | Stock Price [1] | Quarterly Dividend Q3, 2005 [2] | Combined I/B/E/S and Value Line Long-Term Growth Rate [3] | Quarterly Growth Rate [4] | DCF Cost of Equity [5] |
|---|---|---|---|---|---|
| Cascade Natural Gas Corp | $20.19 | $0.24 | 6.2% | 1.5% | 11.3% |
| Keyspan Corp | $33.94 | $0.45 | 4.2% | 1.0% | 9.9% |
| Laclede Group Inc | $29.51 | $0.34 | 4.9% | 1.2% | 9.9% |
| Northwest Natural Gas Co | $34.76 | $0.32 | 5.9% | 1.4% | 9.9% |
| Peoples Energy Corp | $36.76 | $0.55 | 5.6% | 1.4% | 12.0% |
| South Jersey Industries Inc | $29.44 | $0.21 | 4.6% | 1.1% | 7.7% |
| Southwest Gas Corp | $26.81 | $0.20 | 8.5% | 2.1% | 11.9% |
| Wgl Holdings Inc | $30.59 | $0.33 | 4.7% | 1.1% | 9.3% |

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-17.

[2]: Workpaper #2 to Table No. MJV-17.

[3]:Table No. MJV-16, [6].

[4]: {(1 + [3]) ^ (1/4)} - 1.

[5]: {(([2] / [1]) x (1 + [4]) + [4] + 1) ^ 4} - 1.

Table No. MJV-17

DCF Cost of Equity of the 2005 US LDC Sample

Panel B: Multi-Stage DCF (Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

| Company | Stock Price | Quarterly Dividend Q3, 2005 | Combined I/B/E/S and *Value Line* Long-Term Growth Rate | Combined Growth Rate: FY 10 - 11 | Combined Growth Rate: FY 11 - 12 | Combined Growth Rate: FY 12 - 13 | Combined Growth Rate: FY 13 - 14 | Combined Growth Rate: FY 14 - 15 | GDP Long-Term Growth Rate | DCF Cost of Equity |
|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] |
| Cascade Natural Gas Corp | $20.19 | $0.24 | 6.2% | 6.1% | 6.0% | 5.8% | 5.7% | 5.6% | 5.5% | 10.8% |
| Keyspan Corp | $33.94 | $0.45 | 4.2% | 4.4% | 4.6% | 4.8% | 5.1% | 5.3% | 5.5% | 10.8% |
| Laclede Group Inc | $29.51 | $0.34 | 4.9% | 5.0% | 5.1% | 5.2% | 5.3% | 5.4% | 5.5% | 10.3% |
| Northwest Natural Gas Co | $34.76 | $0.32 | 5.9% | 5.8% | 5.7% | 5.7% | 5.6% | 5.6% | 5.5% | 9.6% |
| Peoples Energy Corp | $36.76 | $0.55 | 5.6% | 5.6% | 5.6% | 5.6% | 5.5% | 5.5% | 5.5% | 11.9% |
| South Jersey Industries Inc | $29.44 | $0.21 | 4.6% | 4.8% | 4.9% | 5.1% | 5.2% | 5.4% | 5.5% | 8.4% |
| Southwest Gas Corp | $26.81 | $0.20 | 8.5% | 8.0% | 7.5% | 7.0% | 6.5% | 6.0% | 5.5% | 9.4% |
| Wgl Holdings Inc | $30.59 | $0.33 | 4.7% | 4.8% | 4.9% | 5.1% | 5.2% | 5.4% | 5.5% | 9.9% |

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-17.

[2]: Workpaper #2 to Table No. MJV-17.

[3]: Table No. MJV-16, [6].

[4]: [3] - ([3] - [9]) / 6.

[5]: [4] - ([3] - [9]) / 6.

[6]: [5] - ([3] - [9]) / 6.

[7]: [6] - ([3] - [9]) / 6.

[8]: [7] - ([3] - [9]) / 6.

[9]: Blue Chip Economic Indicators, October 10, 2005, page 15 (Nominal GDP for 2012 - 2016). This number is assumed to be the perpetual growth rate.

[10]: Workpaper #3 to Table No. MJV-17.

Workpaper #1 to Table No. MJV-17

2005 US LDC Sample

Common Stock Prices from November 28, 2005 to December 16, 2005

| Company | 16-Dec-05 | 15-Dec-05 | 14-Dec-05 | 13-Dec-05 | 12-Dec-05 | 09-Dec-05 | 08-Dec-05 | 07-Dec-05 | 06-Dec-05 | 05-Dec-05 | 02-Dec-05 | 01-Dec-05 | 30-Nov-05 | 29-Nov-05 | 28-Nov-05 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | $19.79 | $19.92 | $19.95 | $20.03 | $20.18 | $20.23 | $20.19 | $20.20 | $20.52 | $20.30 | $20.42 | $20.62 | $20.29 | $20.11 | $20.11 | $20.19 |
| Keyspan Corp | $35.38 | $35.15 | $34.58 | $33.83 | $33.50 | $33.50 | $33.55 | $33.37 | $33.35 | $33.69 | $33.77 | $33.89 | $33.56 | $34.03 | $33.93 | $33.94 |
| Laclede Group Inc | $29.34 | $29.50 | $29.49 | $29.50 | $29.48 | $29.30 | $29.10 | $29.32 | $29.65 | $29.35 | $30.16 | $30.24 | $29.96 | $29.20 | $29.02 | $29.51 |
| Northwest Natural Gas Co | $35.40 | $35.30 | $35.20 | $34.95 | $34.67 | $34.71 | $34.40 | $34.40 | $34.58 | $34.61 | $34.94 | $34.89 | $34.36 | $34.55 | $34.50 | $34.76 |
| Peoples Energy Corp | $37.68 | $37.73 | $37.94 | $37.08 | $36.92 | $36.98 | $36.72 | $36.44 | $36.55 | $36.43 | $36.43 | $36.44 | $35.93 | $36.18 | $35.88 | $36.76 |
| South Jersey Industries Inc | $30.27 | $30.24 | $30.29 | $30.19 | $29.99 | $29.77 | $29.47 | $29.32 | $29.76 | $29.95 | $29.44 | $28.96 | $28.75 | $28.40 | $26.85 | $29.44 |
| Southwest Gas Corp | $26.98 | $27.05 | $27.11 | $26.90 | $26.70 | $26.94 | $26.75 | $26.65 | $27.02 | $26.57 | $26.85 | $27.11 | $26.68 | $26.47 | $26.32 | $26.81 |
| Wgl Holdings Inc | $31.14 | $30.58 | $30.64 | $30.25 | $30.09 | $30.20 | $30.46 | $30.62 | $30.86 | $30.84 | $31.06 | $30.99 | $30.42 | $30.51 | $30.21 | $30.59 |

Sources and Notes:
Compustat as of December 27, 2005.
The prices chosen are the daily closing prices from Compustat starting from I/B/E/S forecast date and ending fifteen trading days before.

Workpaper #2 to Table No. MJV-17

2005 US LDC Sample

3rd Quarter 2005 Dividend Payments

| Company | Q3, 2005 |
|---|---|
| Cascade Natural Gas Corp | $0.24 |
| Keyspan Corp | $0.45 |
| Laclede Group Inc | $0.34 |
| Northwest Natural Gas Co | $0.32 |
| Peoples Energy Corp | $0.55 |
| South Jersey Industries Inc | $0.21 |
| Southwest Gas Corp | $0.20 |
| Wgl Holdings Inc | $0.33 |

Compustat as of December 27, 2005.

Workpaper #3 to Table No. MJV-17

DCF Cost of Equity of the 2005 US LDC Sample

Multi - Stage DCF (using the Blue Chip Indicators Long-Term GDP Growth Rate Forecast as the Perpetual Growth Rate)

| Year | Company | Cascade Natural Gas Corp | Keyspan Corp | Laclede Group Inc | Northwest Natural Gas Co | Peoples Energy Corp | South Jersey Industries Inc | Southwest Gas Corp | Wgl Holdings Inc |
|---|---|---|---|---|---|---|---|---|---|
| | Current Stock Price | ($20.19) | ($33.94) | ($29.51) | ($34.76) | ($36.76) | ($29.44) | ($26.81) | ($30.59) |
| YEAR 2005 | Dividend Q4 Estimate | $0.24 | $0.46 | $0.35 | $0.33 | $0.55 | $0.21 | $0.21 | $0.34 |
| YEAR 2006 | Dividend Q1 Estimate | $0.25 | $0.46 | $0.35 | $0.33 | $0.56 | $0.22 | $0.21 | $0.34 |
| YEAR 2006 | Dividend Q2 Estimate | $0.25 | $0.47 | $0.36 | $0.34 | $0.57 | $0.22 | $0.22 | $0.34 |
| YEAR 2006 | Dividend Q3 Estimate | $0.25 | $0.47 | $0.36 | $0.34 | $0.58 | $0.22 | $0.22 | $0.35 |
| YEAR 2006 | Dividend Q4 Estimate | $0.26 | $0.48 | $0.37 | $0.35 | $0.58 | $0.22 | $0.23 | $0.35 |
| YEAR 2007 | Dividend Q1 Estimate | $0.26 | $0.48 | $0.37 | $0.35 | $0.59 | $0.23 | $0.23 | $0.36 |
| YEAR 2007 | Dividend Q2 Estimate | $0.27 | $0.49 | $0.38 | $0.36 | $0.60 | $0.23 | $0.24 | $0.36 |
| YEAR 2007 | Dividend Q3 Estimate | $0.27 | $0.49 | $0.38 | $0.36 | $0.61 | $0.23 | $0.24 | $0.36 |
| YEAR 2007 | Dividend Q4 Estimate | $0.27 | $0.50 | $0.38 | $0.37 | $0.62 | $0.24 | $0.25 | $0.37 |
| YEAR 2008 | Dividend Q1 Estimate | $0.28 | $0.50 | $0.39 | $0.37 | $0.62 | $0.24 | $0.25 | $0.37 |
| YEAR 2008 | Dividend Q2 Estimate | $0.28 | $0.51 | $0.39 | $0.38 | $0.63 | $0.24 | $0.26 | $0.38 |
| YEAR 2008 | Dividend Q3 Estimate | $0.29 | $0.51 | $0.40 | $0.39 | $0.64 | $0.24 | $0.26 | $0.38 |
| YEAR 2008 | Dividend Q4 Estimate | $0.29 | $0.52 | $0.40 | $0.39 | $0.65 | $0.25 | $0.27 | $0.39 |
| YEAR 2009 | Dividend Q1 Estimate | $0.30 | $0.52 | $0.41 | $0.40 | $0.66 | $0.25 | $0.27 | $0.39 |
| YEAR 2009 | Dividend Q2 Estimate | $0.30 | $0.53 | $0.41 | $0.40 | $0.67 | $0.25 | $0.28 | $0.39 |
| YEAR 2009 | Dividend Q3 Estimate | $0.31 | $0.54 | $0.42 | $0.41 | $0.68 | $0.25 | $0.28 | $0.40 |
| YEAR 2009 | Dividend Q4 Estimate | $0.31 | $0.54 | $0.42 | $0.41 | $0.69 | $0.26 | $0.29 | $0.40 |
| YEAR 2010 | Dividend Q1 Estimate | $0.31 | $0.55 | $0.43 | $0.42 | $0.70 | $0.26 | $0.30 | $0.41 |
| YEAR 2010 | Dividend Q2 Estimate | $0.32 | $0.55 | $0.43 | $0.43 | $0.71 | $0.26 | $0.30 | $0.41 |
| YEAR 2010 | Dividend Q3 Estimate | $0.32 | $0.56 | $0.44 | $0.43 | $0.72 | $0.27 | $0.31 | $0.42 |
| YEAR 2010 | Dividend Q4 Estimate | $0.33 | $0.56 | $0.44 | $0.44 | $0.73 | $0.27 | $0.32 | $0.42 |
| YEAR 2011 | Dividend Q1 Estimate | $0.33 | $0.57 | $0.45 | $0.44 | $0.74 | $0.27 | $0.32 | $0.43 |
| YEAR 2011 | Dividend Q2 Estimate | $0.34 | $0.58 | $0.45 | $0.45 | $0.75 | $0.28 | $0.33 | $0.43 |
| YEAR 2011 | Dividend Q3 Estimate | $0.34 | $0.58 | $0.46 | $0.46 | $0.76 | $0.28 | $0.33 | $0.44 |
| YEAR 2011 | Dividend Q4 Estimate | $0.35 | $0.59 | $0.47 | $0.46 | $0.77 | $0.28 | $0.34 | $0.44 |
| YEAR 2012 | Dividend Q1 Estimate | $0.35 | $0.59 | $0.47 | $0.47 | $0.78 | $0.29 | $0.35 | $0.45 |
| YEAR 2012 | Dividend Q2 Estimate | $0.36 | $0.60 | $0.48 | $0.48 | $0.79 | $0.29 | $0.35 | $0.45 |
| YEAR 2012 | Dividend Q3 Estimate | $0.36 | $0.61 | $0.48 | $0.48 | $0.80 | $0.29 | $0.36 | $0.46 |
| YEAR 2012 | Dividend Q4 Estimate | $0.37 | $0.62 | $0.49 | $0.49 | $0.81 | $0.30 | $0.37 | $0.46 |
| YEAR 2013 | Dividend Q1 Estimate | $0.38 | $0.62 | $0.50 | $0.50 | $0.82 | $0.30 | $0.37 | $0.47 |
| YEAR 2013 | Dividend Q2 Estimate | $0.38 | $0.63 | $0.50 | $0.50 | $0.83 | $0.30 | $0.38 | $0.48 |
| YEAR 2013 | Dividend Q3 Estimate | $0.39 | $0.64 | $0.51 | $0.51 | $0.84 | $0.31 | $0.39 | $0.48 |
| YEAR 2013 | Dividend Q4 Estimate | $0.39 | $0.64 | $0.51 | $0.52 | $0.85 | $0.31 | $0.39 | $0.49 |
| YEAR 2014 | Dividend Q1 Estimate | $0.40 | $0.65 | $0.52 | $0.53 | $0.87 | $0.31 | $0.40 | $0.49 |
| YEAR 2014 | Dividend Q2 Estimate | $0.40 | $0.66 | $0.53 | $0.53 | $0.88 | $0.32 | $0.40 | $0.50 |
| YEAR 2014 | Dividend Q3 Estimate | $0.41 | $0.67 | $0.53 | $0.54 | $0.89 | $0.32 | $0.41 | $0.51 |
| YEAR 2014 | Dividend Q4 Estimate | $0.41 | $0.68 | $0.54 | $0.55 | $0.90 | $0.33 | $0.42 | $0.51 |
| YEAR 2015 | Dividend Q1 Estimate | $0.42 | $0.69 | $0.55 | $0.55 | $0.91 | $0.33 | $0.42 | $0.52 |
| YEAR 2015 | Dividend Q2 Estimate | $0.43 | $0.70 | $0.56 | $0.56 | $0.93 | $0.34 | $0.43 | $0.53 |
| YEAR 2015 | Dividend Q3 Estimate | $0.43 | $0.70 | $0.56 | $0.57 | $0.94 | $0.34 | $0.44 | $0.53 |
| YEAR 2015 Q4 | Year 10 Stock Price | $35.51 | $58.19 | $51.09 | $60.79 | $64.24 | $50.90 | $47.99 | $52.84 |
| | Trial COE - Quarterly Rate | 2.6% | 2.6% | 2.5% | 2.3% | 2.8% | 2.0% | 2.3% | 2.4% |
| | Trial COE - Annual Rate | 10.8% | 10.8% | 10.3% | 9.6% | 11.9% | 8.4% | 9.4% | 9.9% |
| | Cost of Equity | 10.8% | 10.8% | 10.3% | 9.6% | 11.9% | 8.4% | 9.4% | 9.9% |
| | (Trial COE - COE) x 100 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Sources and Notes:

All Growth Rate Estimates: Table No. MJV-17, Panel B

Stock Prices and Dividends are from Compustat as of December 27, 2005.

1 See Workpaper #1 to Table No. MJV-17 for the average closing stock price obtained from Compustat.

2 See Workpaper #2 to Table No. MJV-17 for the for the quarterly dividend obtained from Compustat.

3 The Blue Chip Long-Term GDP Growth Rate is used to calculate the Year 10 Stock Price.

{(the Dividend Year 2015 Q3 Estimate) x ((1 + the Perpetual Growth Rate) ^ (1/2))} /

{(Trial COE - Quarterly Rate) - ((1 + the Perpetual Growth Rate) ^ (1/4) -1)}

Table No. MJV-18

Overall Cost of Capital of the 2005 US LDC Sample

Panel A: Simple DCF Method (Quarterly)

| Company | | 3rd Quarter, 2005 Bond Rating [1] | 3rd Quarter, 2005 Preferred Equity Rating [2] | DCF Cost of Equity [3] | DCF Common Equity to Market Value Ratio [4] | Cost of Preferred Equity [5] | DCF Preferred Equity to Market Value Ratio [6] | Cost of Debt [7] | DCF Debt to Market Value Ratio [8] | Union 's Income Tax Rate [9] | Overall After- Tax Cost of Capital [10] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | BBB | - | 11.3% | 0.55 | - | - | 5.2% | 0.45 | 36.1% | 7.7% |
| Keyspan Corp | | A | - | 9.9% | 0.60 | - | - | 4.9% | 0.40 | 36.1% | 7.2% |
| Laclede Group Inc | * | A | A | 9.9% | 0.63 | 4.9% | 0.00 | 4.9% | 0.37 | 36.1% | 7.4% |
| Northwest Natural Gas Co | * | A | - | 9.9% | 0.64 | - | - | 4.9% | 0.36 | 36.1% | 7.5% |
| Peoples Energy Corp | | A | - | 12.0% | 0.61 | - | - | 4.9% | 0.39 | 36.1% | 8.5% |
| South Jersey Industries Inc | | BBB | - | 7.7% | 0.71 | - | - | 5.2% | 0.29 | 36.1% | 6.4% |
| Southwest Gas Corp | * | BBB | - | 11.9% | 0.44 | - | - | 5.2% | 0.56 | 36.1% | 7.1% |
| Wgl Holdings Inc | | AA | AA | 9.3% | 0.69 | 4.8% | 0.01 | 4.8% | 0.30 | 36.1% | 7.4% |
| Average [a] | | | | 10.2% | 0.61 | 4.8% | 0.00 | 5.0% | 0.39 | 36.1% | 7.4% |
| Average [b] | | | | 10.7% | 0.57 | 4.9% | 0.00 | 5.1% | 0.43 | 36.1% | 7.4% |

Sources and Notes:

[1]: Compustat as of December 27, 2005.
Ratings for South Jersey Industries are for South Jersey Gas,
and are taken from Moody's (last accessed 1/17/2006).
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-17; Panel A, [5].
[4]: Table No. MJV-15, [1].
[5]: [7].
[6]: Table No. MJV-15, [2].
[7]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005.
Yield on AA-rated bond = Yield on A-rated bond + 50% x (Yield on A-rated bond - Yield on BBB-rated bond)
Yield on BBB-rated bond = Yield on A-rated bond + 0.30%

[8]: Table No. MJV-15, [3].
[9]: Provided by Union.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[a]: Average over all companies.
[b]: Average for companies marked with an asterisk.
* Represents companies that have revenues from regulated activities greater than 70%.

Table No. MJV-18

Overall Cost of Capital of the 2005 US LDC Sample

Panel B: Multi-Stage DCF (Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

| Company | | 3rd Quarter, 2005 Bond Rating [1] | 3rd Quarter, 2005 Preferred Equity Rating [2] | DCF Cost of Equity [3] | DCF Common Equity to Market Value Ratio [4] | Cost of Preferred Equity [5] | DCF Preferred Equity to Market Value Ratio [6] | Cost of Debt [7] | DCF Debt to Market Value Ratio [8] | Union 's Income Tax Rate [9] | Overall After- Tax Cost of Capital [10] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | BBB | - | 10.8% | 0.55 | - | - | 5.2% | 0.45 | 36.1% | 7.4% |
| Keyspan Corp | | A | - | 10.8% | 0.60 | - | - | 4.9% | 0.40 | 36.1% | 7.7% |
| Laclede Group Inc | * | A | A | 10.3% | 0.63 | 4.9% | 0.00 | 4.9% | 0.37 | 36.1% | 7.6% |
| Northwest Natural Gas Co | * | A | - | 9.6% | 0.64 | - | - | 4.9% | 0.36 | 36.1% | 7.3% |
| Peoples Energy Corp | | A | - | 11.9% | 0.61 | - | - | 4.9% | 0.39 | 36.1% | 8.5% |
| South Jersey Industries Inc | | BBB | - | 8.4% | 0.71 | - | - | 5.2% | 0.29 | 36.1% | 6.9% |
| Southwest Gas Corp | * | BBB | - | 9.4% | 0.44 | - | - | 5.2% | 0.56 | 36.1% | 6.0% |
| Wgl Holdings Inc | | AA | AA | 9.9% | 0.69 | 4.8% | 0.01 | 4.8% | 0.30 | 36.1% | 7.8% |
| Average [a] | | | | 10.1% | 0.61 | 4.8% | 0.00 | 5.0% | 0.39 | 36.1% | 7.4% |
| Average [b] | | | | 10.0% | 0.57 | 4.9% | 0.00 | 5.1% | 0.43 | 36.1% | 7.1% |

Sources and Notes:
[1]: Compustat as of December 27, 2005.
Ratings for South Jersey Industries are for South Jersey Gas,
and are taken from Moody's (last accessed 1/17/2006).
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-17; Panel B, [10].
[4]: Table No. MJV-15, [1].
[5]: [7].
[6]: Table No. MJV-15, [2].
[7]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005.
Yield on AA-rated bond = Yield on A-rated bond + 50% x (Yield on A-rated bond - Yield on BBB-rated bond)
Yield on BBB-rated bond = Yield on A-rated bond + 0.30%
[8]: Table No. MJV-15, [3].
[9]: Provided by Union.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}
[a]: Average over all companies.
[b]: Average for companies marked with an asterisk.
* Represents companies that have revenues from regulated activities greater than 70%.

Table No. MJV-19

Deemed Capital Structure Consistent with 2005 US LDC Sample's DCF Cost of Capital Estimates

**Panel A: Using Union's Allowed ROE: 9.63%**

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using All Companies** | | | | | | | | |
| Simple DCF Quarterly | 7.4% | 31.3% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 65.5% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 7.4% | 31.1% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 65.7% |
| **Using Companies that have 2004 revenues from regulated activities greater than 70%.** | | | | | | | | |
| Simple DCF Quarterly | 7.4% | 30.9% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 65.9% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 7.1% | 35.9% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 60.9% |

Sources and Notes:

[1]: Table No. MJV-18; Panels A - B, [10].

[2]: 1 - [5] - [8]

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

Table No. MJV-19

Deemed Capital Structure Consistent with 2005 US LDC Sample's DCF Cost of Capital Estimates

**Panel B: Using Union's Estimated ROE for 2006: 8.89%**

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using All Companies** | | | | | | | | |
| Simple DCF Quarterly | 7.4% | 22.8% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 73.9% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 7.4% | 22.6% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 74.1% |
| **Using Companies that have 2004 revenues from regulated activities greater than 70%.** | | | | | | | | |
| Simple DCF Quarterly | 7.4% | 22.4% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 74.4% |
| Multi-Stage DCF - Using the Blue-Chip Long-Term GDP Growth Forecast as the Perpetual Rate | 7.1% | 28.1% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 68.7% |

Sources and Notes

[1]: Table No. MJV-18; Panels A - B, [10].

[2]: 1 - [5] - [8].

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

Table No. MJV-20

Risk Positioning Cost of Equity of the 2005 US LDC Sample

Using Unadjusted Value Line Betas and the Long-Term Risk-Free Rate

| Company | | Long-Term Risk-Free Rate [1] | Unadjusted Value Line Beta on Market [2] | Long-Term Market Risk Premium [3] | CAPM Cost of Equity [4] | ECAPM (1.0%) Cost of Equity [5] | ECAPM (2.0%) Cost of Equity [6] |
|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | 4.8% | 0.67 | 5.25% | 8.3% | 8.7% | 9.0% |
| Keyspan Corp | | 4.8% | 0.75 | 5.25% | 8.7% | 9.0% | 9.2% |
| Laclede Group Inc | * | 4.8% | 0.67 | 5.25% | 8.3% | 8.7% | 9.0% |
| Northwest Natural Gas Co | * | 4.8% | 0.52 | 5.25% | 7.5% | 8.0% | 8.5% |
| Peoples Energy Corp | | 4.8% | 0.75 | 5.25% | 8.7% | 9.0% | 9.2% |
| South Jersey Industries Inc | | 4.8% | 0.45 | 5.25% | 7.2% | 7.7% | 8.3% |
| Southwest Gas Corp | * | 4.8% | 0.67 | 5.25% | 8.3% | 8.7% | 9.0% |
| Wgl Holdings Inc | | 4.8% | 0.67 | 5.25% | 8.3% | 8.7% | 9.0% |
| Average [a] | | 4.8% | 0.64 | 5.25% | 8.2% | 8.5% | 8.9% |
| Average [b] | | 4.8% | 0.63 | 5.25% | 8.1% | 8.5% | 8.9% |

Sources and Notes:

[1]: Consensus Forecast as of January 9, 2006.

Sum of 10-Year Canadian Government Bond Forecast (4.6%) + Maturity Premium of 0.20%.

See Workpaper #2 to Table No. MJV-9, Panel C for maturity premium calculation.

[2]: Workpaper # 1 to Table No. MJV-20.

[3]: Vilbert Written Evidence, Appendix B.

[4]: [1] + ([2] x [3]).

[5]: ([1] + 1.0%) + [2] x ([3] - 1.0%).

[6]: ([1] + 2.0%) + [2] x ([3] - 2.0%).

[a]: Average over all companies.

[b]: Average for companies marked with an asterisk.

* Represents companies that have revenues from regulated activities greater than 70%.

## Workpaper # 1 to Table No. MJV-20

## 2005 US LDC Sample

## Value Line Betas

| Company | Beta as of December 16, 2005 [1] | Unadjusted Beta [2] |
|---|---|---|
| Cascade Natural Gas Corp | 0.80 | 0.67 |
| Keyspan Corp | 0.85 | 0.75 |
| Laclede Group Inc | 0.80 | 0.67 |
| Northwest Natural Gas Co | 0.70 | 0.52 |
| Peoples Energy Corp | 0.85 | 0.75 |
| South Jersey Industries Inc | 0.65 | 0.45 |
| Southwest Gas Corp | 0.80 | 0.67 |
| Wgl Holdings Inc | 0.80 | 0.67 |

Sources and Notes:
[1]: Value Line Investment Survey, Standard Edition as of December 16, 2005.
[2]: The reported beta in [1] by Value Line is unadjusted
using the formula: ([1] - .35) / .67.

Table No. MJV-21

Overall Cost of Capital of the 2005 US LDC Sample

Panel A: CAPM Cost of Equity Based on Unadjusted Value Line Betas and a Long-Term Risk-Free Rate

| Company | | CAPM Cost of Equity [1] | 5-Year Average Common Equity to Market Value Ratio [2] | Weighted - Average Cost of Preferred Equity [3] | 5-Year Average Preferred Equity to Market Value Ratio [4] | Weighted - Average Cost of Debt [5] | 5-Year Average Debt to Market Value Ratio [6] | Union 's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | 8.3% | 0.59 | - | - | 5.2% | 0.41 | 36.1% | 6.3% |
| Keyspan Corp | | 8.7% | 0.53 | 4.9% | 0.01 | 4.9% | 0.46 | 36.1% | 6.1% |
| Laclede Group Inc | * | 8.3% | 0.61 | 4.9% | 0.00 | 4.9% | 0.39 | 36.1% | 6.3% |
| Northwest Natural Gas Co | * | 7.5% | 0.61 | 4.9% | 0.01 | 4.9% | 0.38 | 36.1% | 5.9% |
| Peoples Energy Corp | | 8.7% | 0.63 | - | - | 4.9% | 0.37 | 36.1% | 6.6% |
| South Jersey Industries Inc | | 7.2% | 0.60 | 5.2% | 0.00 | 5.2% | 0.40 | 36.1% | 5.6% |
| Southwest Gas Corp | * | 8.3% | 0.40 | - | - | 5.2% | 0.60 | 36.1% | 5.3% |
| Wgl Holdings Inc | | 8.3% | 0.67 | 4.8% | 0.01 | 4.8% | 0.31 | 36.1% | 6.6% |
| Average [a] | | 8.2% | 0.58 | 4.9% | 0.00 | 5.0% | 0.42 | 36.1% | 6.1% |
| Average [b] | | 8.1% | 0.55 | 4.9% | 0.00 | 5.0% | 0.44 | 36.1% | 5.9% |

Sources and Notes:

[1]: Table No. MJV-20; Panel A, [4].

[2]: Table No. MJV-15, [4].

[3]: Workpaper #2 to Table No. MJV-21 ; Panel B, [7].

[4]: Table No. MJV-15, [5].

[5]: Workpaper #2 to Table No. MJV-21 ; Panel A, [7].

[6]: Table No. MJV-15, [6].

[7]: Provided by Union.

[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

[a]: Average over all companies.

[b]: Average for companies marked with an asterisk.

* Represents companies that have revenues from regulated activities greater than 70%.

Table No. MJV-21

Overall Cost of Capital of the 2005 US LDC Sample

Panel B: ECAPM (1.0%) Cost of Equity Based on Unadjusted Value Line Betas and a Long-Term Risk-Free Rate

| Company | | ECAPM (1.0%) Cost of Equity [1] | 5-Year Average Common Equity to Market Value Ratio [2] | Weighted - Average Cost of Preferred Equity [3] | 5-Year Average Preferred Equity to Market Value Ratio [4] | Weighted - Average Cost of Debt [5] | 5-Year Average Debt to Market Value Ratio [6] | Union 's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | 8.7% | 0.59 | - | - | 5.2% | 0.41 | 36.1% | 6.5% |
| Keyspan Corp | | 9.0% | 0.53 | 4.9% | 0.01 | 4.9% | 0.46 | 36.1% | 6.3% |
| Laclede Group Inc | * | 8.7% | 0.61 | 4.9% | 0.00 | 4.9% | 0.39 | 36.1% | 6.5% |
| Northwest Natural Gas Co | * | 8.0% | 0.61 | 4.9% | 0.01 | 4.9% | 0.38 | 36.1% | 6.1% |
| Peoples Energy Corp | | 9.0% | 0.63 | - | - | 4.9% | 0.37 | 36.1% | 6.8% |
| South Jersey Industries Inc | | 7.7% | 0.60 | 5.2% | 0.00 | 5.2% | 0.40 | 36.1% | 5.9% |
| Southwest Gas Corp | * | 8.7% | 0.40 | - | - | 5.2% | 0.60 | 36.1% | 5.5% |
| Wgl Holdings Inc | | 8.7% | 0.67 | 4.8% | 0.01 | 4.8% | 0.31 | 36.1% | 6.8% |
| Average [a] | | 8.5% | 0.58 | 4.9% | 0.00 | 5.0% | 0.42 | 36.1% | 6.3% |
| Average [b] | | 8.5% | 0.55 | 4.9% | 0.00 | 5.0% | 0.44 | 36.1% | 6.1% |

Sources and Notes:
[1]: Table No. MJV-20; Panel A, [5].
[2]: Table No. MJV-15, [4].
[3]: Workpaper #2 to Table No. MJV-21 ; Panel B, [7].
[4]: Table No. MJV-15, [5].
[5]: Workpaper #2 to Table No. MJV-21 ; Panel A, [7].
[6]: Table No. MJV-15, [6].
[7]: Provided by Union.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

[a]: Average over all companies.
[b]: Average for companies marked with an asterisk.
* Represents companies that have revenues from regulated activities greater than 70%.

Table No. MJV-21

Overall Cost of Capital of the 2005 US LDC Sample

Panel C: ECAPM (2.0%) Cost of Equity Based on Unadjusted Value Line Betas and a Long-Term Risk-Free Rate

| Company | | ECAPM (2.0%) Cost of Equity [1] | 5-Year Average Common Equity to Market Value Ratio [2] | Weighted - Average Cost of Preferred Equity [3] | 5-Year Average Preferred Equity to Market Value Ratio [4] | Weighted - Average Cost of Debt [5] | 5-Year Average Debt to Market Value Ratio [6] | Union 's Income Tax Rate [7] | Overall After- Tax Cost of Capital [8] |
|---|---|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | * | 9.0% | 0.59 | - | - | 5.2% | 0.41 | 36.1% | 6.7% |
| Keyspan Corp | | 9.2% | 0.53 | 4.9% | 0.01 | 4.9% | 0.46 | 36.1% | 6.4% |
| Laclede Group Inc | * | 9.0% | 0.61 | 4.9% | 0.00 | 4.9% | 0.39 | 36.1% | 6.7% |
| Northwest Natural Gas Co | * | 8.5% | 0.61 | 4.9% | 0.01 | 4.9% | 0.38 | 36.1% | 6.4% |
| Peoples Energy Corp | | 9.2% | 0.63 | - | - | 4.9% | 0.37 | 36.1% | 6.9% |
| South Jersey Industries Inc | | 8.3% | 0.60 | 5.2% | 0.00 | 5.2% | 0.40 | 36.1% | 6.3% |
| Southwest Gas Corp | * | 9.0% | 0.40 | - | - | 5.2% | 0.60 | 36.1% | 5.6% |
| Wgl Holdings Inc | | 9.0% | 0.67 | 4.8% | 0.01 | 4.8% | 0.31 | 36.1% | 7.1% |
| Average [a] | | 8.9% | 0.58 | 4.9% | 0.00 | 5.0% | 0.42 | 36.1% | 6.5% |
| Average [b] | | 8.9% | 0.55 | 4.9% | 0.00 | 5.0% | 0.44 | 36.1% | 6.3% |

Sources and Notes:

[1]: Table No. MJV-20; Panel A, [6].

[2]: Table No. MJV-15, [4].

[3]: Workpaper #2 to Table No. MJV-21 ; Panel B, [7].

[4]: Table No. MJV-15, [5].

[5]: Workpaper #2 to Table No. MJV-21 ; Panel A, [7].

[6]: Table No. MJV-15, [6].

[7]: Provided by Union.

[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

[a]: Average over all companies.

[b]: Average for companies marked with an asterisk.

* Represents companies that have revenues from regulated activities greater than 70%.

Workpaper #1 to Table No. MJV-21

2005 US LDC Sample

Panel A: Bond Rating Summary, 2000 to 3rd Quarter, 2005

| Company | 3rd Quarter, 2005<br>[1] | 2004<br>[2] | 2003<br>[3] | 2002<br>[4] | 2001<br>[5] | 2000<br>[6] |
|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | BBB | BBB | BBB | BBB | BBB | BBB |
| Keyspan Corp | A | A | A | A | A | A |
| Laclede Group Inc | A | A | A | A | AA | AA |
| Northwest Natural Gas Co | A | A | A | A | A | A |
| Peoples Energy Corp | A | A | A | A | A | A |
| South Jersey Industries Inc | BBB | BBB | BBB | BBB | BBB | BBB |
| Southwest Gas Corp | BBB | BBB | BBB | BBB | BBB | BBB |
| Wgl Holdings Inc | AA | AA | AA | AA | AA | AA |

Sources and Notes:

[1] - [6]: Compustat as of December 27, 2005.

Ratings for South Jersey Industries are for South Jersey Gas, and are taken from Moody's (last accessed 1/17/2006).

Workpaper #1 to Table No. MJV-21

2005 US LDC Sample

Panel B: Preferred Stock Rating Summary, 2000 to 3rd Quarter, 2005

| Company | 3rd Quarter, 2005<br>[1] | 2004<br>[2] | 2003<br>[3] | 2002<br>[4] | 2001<br>[5] | 2000<br>[6] |
|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | - | - | - | - | - | - |
| Keyspan Corp | - | A | A | A | A | A |
| Laclede Group Inc | A | A | A | A | AA | AA |
| Northwest Natural Gas Co | - | - | - | A | A | A |
| Peoples Energy Corp | - | - | - | - | - | - |
| South Jersey Industries Inc | - | BBB | BBB | BBB | BBB | BBB |
| Southwest Gas Corp | - | - | - | - | - | - |
| Wgl Holdings Inc | AA | AA | AA | AA | AA | AA |

Sources and Notes:

[1] - [6]: Preferred equity ratings are assumed equal to the company's bond rating reported in Workpaper #1 to Table No. MJV-21, Panel A.

Workpaper #2 to Table No. MJV-21

2005 US LDC Sample

Panel A: Bond Yield Summary, 2000 to 3rd Quarter, 2005

| Company | 3rd Quarter, 2005<br>[1] | 2004<br>[2] | 2003<br>[3] | 2002<br>[4] | 2001<br>[5] | 2000<br>[6] | 5-Year Average<br>[7] |
|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% |
| Keyspan Corp | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% |
| Laclede Group Inc | 4.90% | 4.90% | 4.90% | 4.90% | 4.75% | 4.75% | 4.86% |
| Northwest Natural Gas Co | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% |
| Peoples Energy Corp | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% |
| South Jersey Industries Inc | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% |
| Southwest Gas Corp | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% |
| Wgl Holdings Inc | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% |

Sources and Notes:

[1] - [6]: Ratings based on Workpaper #1 to Table No. MJV-21, Panel A and bond yields from CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005.

Yield on AA-rated bond = Yield on A-rated bond + 50% x (Yield on A-rated bond - Yield on BBB-rated bond)

Yield on BBB-rated bond = Yield on A-rated bond + 0.30%

[7]: {[1] x 0.75 + [2] + [3] + [4] + [5]+ [6] x 0.25}/ 5.

Workpaper #2 to Table No. MJV-21

2005 US LDC Sample

Panel B: Preferred Stock Yield Summary, 2000 to 3rd Quarter, 2005

| Company | 3rd Quarter, 2005 [1] | 2004 [2] | 2003 [3] | 2002 [4] | 2001 [5] | 2000 [6] | 5-Year Average [7] |
|---|---|---|---|---|---|---|---|
| Cascade Natural Gas Corp | - | - | - | - | - | - | - |
| Keyspan Corp | - | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% | 4.90% |
| Laclede Group Inc | 4.90% | 4.90% | 4.90% | 4.90% | 4.75% | 4.75% | 4.86% |
| Northwest Natural Gas Co | - | - | - | 4.90% | 4.90% | 4.90% | 4.90% |
| Peoples Energy Corp | - | - | - | - | - | - | - |
| South Jersey Industries Inc | - | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% | 5.20% |
| Southwest Gas Corp | - | - | - | - | - | - | - |
| Wgl Holdings Inc | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% | 4.75% |

Sources and Notes:

[1] - [6]: Ratings based on Workpaper #1 to Table No. MJV-21, Panel A.

Preferred stock yields are assumed equal to the bond yields (see Workpaper #2 to Table No. MJV-21, Panel A).

[7]: {[1] x 0.75 + [2] + [3] + [4] + [5]+ [6] x 0.25}/ 5.

Table No. MJV-22

Deemed Capital Structure Consistent with 2005 US LDC Sample's Risk Positioning Cost of Capital Estimates

**Panel A: Using Union's Allowed ROE: 9.63%**

Using All Companies

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free rates over all companies:** | | | | | | | | |
| CAPM using Unadjusted 60-Month Betas | 6.1% | 51.3% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 45.5% |
| ECAPM (1.0%) using Undjusted 60-Month Betas | 6.3% | 48.1% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 48.7% |
| ECAPM (2.0%) using Undjusted 60-Month Betas | 6.5% | 44.9% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 51.9% |

Sources and Notes:

[1]: Table No. MJV-21; Panels A - G, [8].

[2]: 1 - [5] - [8].

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

Table No. MJV-22

Deemed Capital Structure Consistent with 2005 US LDC Sample's Risk Positioning Cost of Capital Estimates

**Panel B: Using Union's Estimated ROE for 2006: 8.89%**

Using All Companies

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free rates over all companies:** | | | | | | | | |
| CAPM using Unadjusted 60-Month Betas | 6.1% | 45.4% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 51.4% |
| ECAPM (1.0%) using Undjusted 60-Month Betas | 6.3% | 41.8% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 55.0% |
| ECAPM (2.0%) using Undjusted 60-Month Betas | 6.5% | 38.2% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 58.6% |

Sources and Notes:

[1]: Table No. MJV-21; Panels A - G, [8].

[2]: 1 - [5] - [8].

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

Table No. MJV-22

Deemed Capital Structure Consistent with 2005 US LDC Sample's Risk Positioning Cost of Capital Estimates

**Panel C: Using Union's Allowed ROE: 9.63%**

Using Companies that have 2004 revenues from regulated activities greater than 70%.

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Allowed ROE [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| **Using Long-Term Risk-Free rates over all companies:** | | | | | | | | |
| CAPM using Unadjusted 60-Month Betas | 5.9% | 53.7% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 43.1% |
| ECAPM (1%) using Undjusted 60-Month Betas | 6.1% | 50.5% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 46.3% |
| ECAPM (2%) using Undjusted 60-Month Betas | 6.3% | 47.4% | 4.9% | 36.1% | 3.2% | 4.9% | 9.63% | 49.4% |

Sources and Notes:

[1]: Table No. MJV-21; Panels A - G, [8].

[2]: 1 - [5] - [8].

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Provided by Union.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

Table No. MJV-22

Deemed Capital Structure Consistent with 2005 US LDC Sample's Risk Positioning Cost of Capital Estimates

**Panel D: Using Union's Estimated ROE for 2006: 8.89%**

Using Companies that have 2004 revenues from regulated activities greater than 70%.

| | Overall Cost of Capital [1] | Union's Deemed Debt Ratio [2] | Union's Cost of Debt [3] | Union's Tax Rate [4] | Union's Preferred Equity Ratio [5] | Union's Cost of Preferred Equity [6] | Estimated ROE for 2006 [7] | Union's Deemed Equity Ratio [8] |
|---|---|---|---|---|---|---|---|---|
| ***Using Long-Term Risk-Free rates over all companies:*** | | | | | | | | |
| CAPM using Unadjusted 60-Month Betas | 5.9% | 48.1% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 48.7% |
| ECAPM (1%) using Undjusted 60-Month Betas | 6.1% | 44.6% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 52.2% |
| ECAPM (2%) using Undjusted 60-Month Betas | 6.3% | 41.0% | 4.9% | 36.1% | 3.2% | 4.9% | 8.89% | 55.8% |

Sources and Notes:

[1]: Table No. MJV-21; Panels A - G, [8].

[2]: 1 - [5] - [8].

[3]: CIBC Worldmarkets, BIGAR Indices Monthly Report, December 31, 2005. Based on most recent rating by Dominion Bond Rating Service.

[4]: Provided by Union.

[5]: Provided by Union.

[6]: Cost of preferred equity assumed equal to cost of debt.

[7]: Estimated for 2006 based on Ontario Energy Board's return on equity formula.

[8]: {[1] - (1 - [5]) x [3] x (1 - [4]) - [5] x [6] x (1 - [4])} / {[7] - [3] x (1 - [4])}.

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Broeders

In J.O-4-4-2, please identify for each year the amount attributable to each of the three factors that contributed to overearnings.

---

| Particulars ($ millions) | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| Weather colder/(warmer) (1) | 6.9 | 3.9 | (12.8) | (3.5) |
| FT RAM | 5.0 | 14.0 | 11.7 | 22.0 |
| UFG (2) (3) | (3.9) | (11.4) | 18.4 | 23.7 |

Notes:

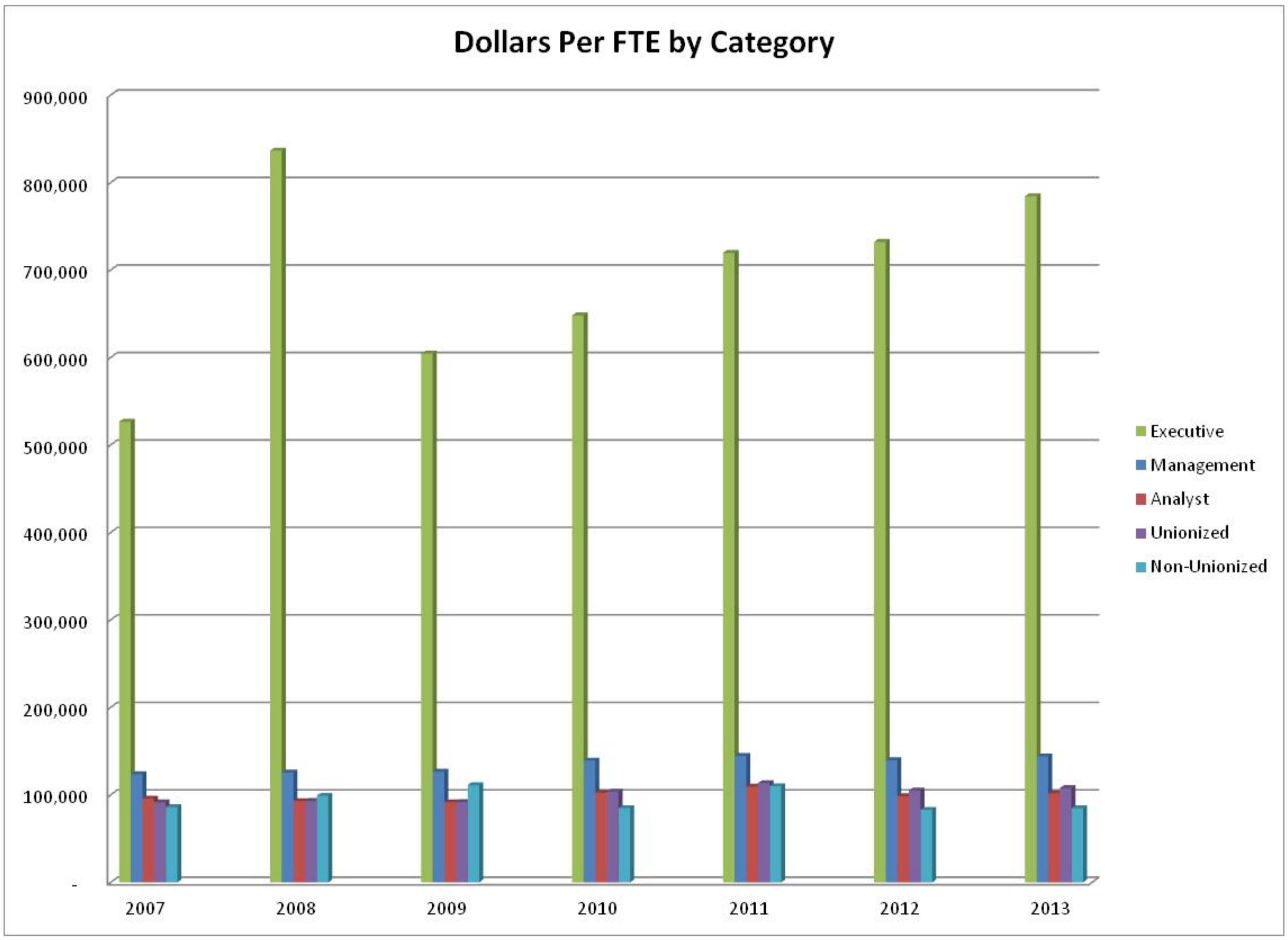
(1) Revenue impact only; does not include compressor fuel, cost mitigation and other related impacts
(2) Net of intra-period WACOG
(3) (higher than Board-approved)/lower than Board-approved

UNION GAS LIMITED

Undertaking of Mr. MacIntosh
To Ms. Cummings

For the data provided on Pages 1 to 6 of Attachment 1, to graph the dollars per FTE for the five categories of employee average yearly compensation from 2007 to 2013.

---------------------------------------------------------------------------------------------------------------



UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Shorts

Please provide the reason for the difference in total supply at cost.

---

The difference is that page 2, line 1 of J.D-14-2-1, Attachment 1 includes $426,000 of third party storage which is shown at line 18 of page 1.

UNION GAS LIMITED

Undertaking of Mr.
To Mr.

Was there a full or half year assumption in the calculation in the first year operating cost of Parkway West in J.B-1-7-8?

---

The figure of $16.4 is based on a full year assumption using a depreciation rate of 3.52%.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Wood

Please provide the highest peak day flow through the Owen Sound line for the past 10 years and the actual winter day set delivery pressure for the Kitchener Gate Station for the Winter 2011/12.
------------------------------------------------------------------------------------------------------------

Detailed data for peak day flows is only available for the past five years. The highest peak day flows through the Owen Sound take-off for the past five years are:

| Year | Volume (km3/d) | Heating Degree |
|---|---|---|
| 2008 | 4,947 | 34.7 |
| 2009 | 5,138 | 36.1 |
| 2010 | 4,823 | 31.4 |
| 2011 | 4,979 | 35.7 |
| 2012 | 4,480 | 28.8 |

The actual winter set delivery pressure for the Kitchener Gate Station for Winter 2011/2012 was 1,470 kPag.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Shorts

Please provide responsibility of system gas portfolio at Parkway.

---

| | 2011/2012 | 2012/2013 | 2013/2014 |
|---|---|---|---|
| System: | | | |
| Parkway | 31% | 31% | 31% |
| Dawn | 69% | 62% | 62% |
| Kirkwall | 0% | 7% | 7% |

UNION GAS LIMITED

Undertaking of Mr. Ross
To Mr. Shorts

Please confirm whether the contracts were delivered to the Union CDA.

---

Confirmed. Historical TCPL contracts were delivered to Union CDA.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Shorts

Please provide total Union capacity to Eastern Zone, winter 2011, 2012.

---

Eastern Zone firm transportation capacity that Union held as of November 1, 2011 in GJ/d as shown at Exhibit D3 Tab 2, Schedule 5)

| | |
|---|---|
| South Portfolio | |
| 1) Dawn to Union CDA | 60,000 |
| 2) Empress to Union CDA | 71,327 |
| North Portfolio | |
| 3) Empress to Union NCDA | 10,756 |
| 4) Empress to Union EDA | 59,251 |
| 5) Parkway to Union EDA | 35,000 |
| 6) Parkway to Union CDA | 80,000 |
| Total | 316,334 GJ/d |

UNION GAS LIMITED

Undertaking of Mr. Wolnik
To Mr. Redford

Reference J.D-16-13-1

In the response to b) iii), Union implies that the increased integrity space is required because of a change in modeling assumptions.

a) Please describe the assumption changes and if the modeling changes are intended to reflect actual storage performance.

b) Please indicate why these modelling changes are required at this time.

c) Please confirm that the additional hysteresis affects have not been influenced in any way by any of the storage development programs on existing pools (including, but not limited to, adding additional wells, delta pressuring, lowering cushion, down hole simulation programs, adding compression or de-bottlenecking gathering lines etc.) that Union has implemented over the last 10 years? If Union cannot confirm this, please explain why in detail.

---

a) The assumptions resulting in an increase in the hysteresis component of system integrity space include the following:
   i) The maximum hysteresis was revised to reflect well interference to better reflect actual storage performance.
   ii) The uncertainty around the expected maximum hysteresis was changed from a range between -5 psi and +10 psi to a range between -10% and +10%.
   iii) Changes to the methodology used to allocate the total calculated system integrity space (i.e. 9.5 PJ) to reflect diversity more accurately amongst all of the operational components.

b) The modeling changes were incorporated at this time to provide updated information for Union's 2013 Rates proceeding.

c) As indicated in Union's evidence Ex D1 T9 Page 3 well interference depends on the individual pool characteristics, system demands and length of sustained withdrawals or injections. All of these factors, including storage development programs, will have an influence on well interference. Due to the complexity and variability of hysteresis effects, Union cannot confirm the impact. However since the hysteresis component is a measure of the uncertainty, and not the absolute hysteresis. It is expected that the impact of these projects would be minimal.

UNION GAS LIMITED

Undertaking of Mr. Mondrow
To Mr. Wood

Please provide proportion of the volumes leaving Parkway on an annualized basis that serve in-franchise customers.

---

The proportion of the volumes leaving Parkway on an annualized basis to serve CDA in-franchise customers are:

| | |
|---|---|
| 2007 | 29.20% |
| 2008 | 16.75% |
| 2009 | 6.44% |
| 2010 | 8.97% |
| 2011 | 7.35% |

UNION GAS LIMITED

Undertaking of Mr. Mondrow
To Mr. Shorts

Please provide the monthly averages for each month for the last 12 months to the end of May.
---------------------------------------------------------------------------------------------------------------

Dawn to Parkway Average Natural Gas Price Differential (US$/MMBtu)

| Jun'11 | Jul'11 | Aug'11 | Sep'11 | Oct'11 | Nov'11 | Dec'11 | Jan'12 | Feb'12 | Mar'12 | Apr'12 | May'12 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.04 | 0.04 | 0.03 | 0.04 | 0.04 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.06 | 0.03 |

Note: Based on Dawn-Parkway Physical trading spread (USD/MMBTU) as reported by NGX

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Shorts

3. [J.C-3-14-1 Attachment 3] This exhibit indicates that there are 261 customers in various rate classes that Union classifies as manufacturers. This exhibit does not refer to either M2 or Rate 10 customers. By way of clarification, are there any customers served under the auspices of Rate M2 and Rate 10 that Union would classify as manufacturers? If so, please provide the number of such customers in each rate class.

   By cross-referencing the information in this exhibit pertaining to the number of manufacturers served by Union and the rate impact information shown in Exhibits J.F-2- 5-1 and J.H-1-14-2, please indicate the number of manufacturers being served by Union in each rate class who will be facing a rate increase greater than 2% if all of the relief requested by Union in this application is approved.
   customers of the rate impacts?

10. Revenue Requirement

   [J.F-2-5-1] Slides 5 and 6 in this presentation to Union's Board of Directors contained rate impact information. Please modify those slides to show the rate impacts in a scenario where the revenue deficiency for 2013 is zero. We are interested in obtaining a presentation of this nature that will separate the impact of the cost allocation and rate design changes Union is proposing from the revenue deficiency amount being requested for 2013.

11. H. Rate Design

   [J.H-1-14-2] Is the information presented in this interrogatory response compatible with the impacts that were presented to Union's Directors in Exhibit J.F-2-5-1? If not, then please revise the impacts presented to Union's Directors in Exhibit J.F-2-5-1 to reflect the information contained in this exhibit.

Also, please provide a status report on the presentations to the T1 customers of the rate impacts?

---

3. Please see the response at Exhibit JT1.16 for the number of M1 and M2 customers that are manufacturers.

   Based on Union's 2013 proposed delivery rates, Union estimates that all 9,620 manufacturers identified in Rate M1, Rate M2, Rate 01 and Rate 10 will face a delivery rate increase of greater than 2%.

10. Union's response is at p. 166 of the June 1, 2012 transcript.

11. Please see Attachment 1 for the updated slides.

Union has provided additional information to existing T1 customers about the proposed T1 and T2 rate proposal at customer meeting’s in London and Burlington in the May/June 2012 timeframe. Please see Attachment 2 for the presentation made at the London meeting in June.

# Annual Bill Impacts – General Service

| General Service Rate Class | Total Bill Impact | Total Bill Impact |
|---|---|---|
| Union North | | |
| Small Volume Rate 01 (@ 2,200 $m^3$/yr) | $ 59 - $ 76 | 7 % – 9 % |
| Large Volume Rate 10 (@ 93,000 $m^3$/yr) | $ 296 – $ 1,026 | 1 % – 4 % |
| | | |
| Union South | | |
| Small Volume Rate M1 (@ 2,200 $m^3$/yr) | $ 19 | 3 % |
| Large Volume Rate M2 (@ 73,000 $m^3$/yr) | $ 446 | 3 % |

# Average Delivery Rate Impacts – Contract Rate Classes

| Rate Class | Rate Change (cents/m$^3$) | Rate Change ($/GJ) | Delivery Bill Impact (%) |
|---|---|---|---|
| M4 | 0.5563 | 0.147 | 20 |
| M5A | 0.6941 | 0.184 | 42 |
| M7 | 0.1295 | 0.034 | 5 |
| M9 | (0.0551) | (0.015) | (4) |
| M10 | 0.4527 | 0.120 | 18 |
| T1 – Small | 0.4116 | 0.109 | 33 |
| T1 – Average | 0.2738 | 0.072 | 19 |
| T1 – Large | (0.1206) | (0.032) | (19) |
| T3 | 0.0599 | 0.016 | 4 |
| Rate 20 | 0.6734 | 0.178 | 43 |
| Rate 25 | 0.7826 | 0.207 | 43 |
| Rate 100 | 0.1941 | 0.051 | 29 |

# 2013 Cost of Service Filing
# EB-2011-0210

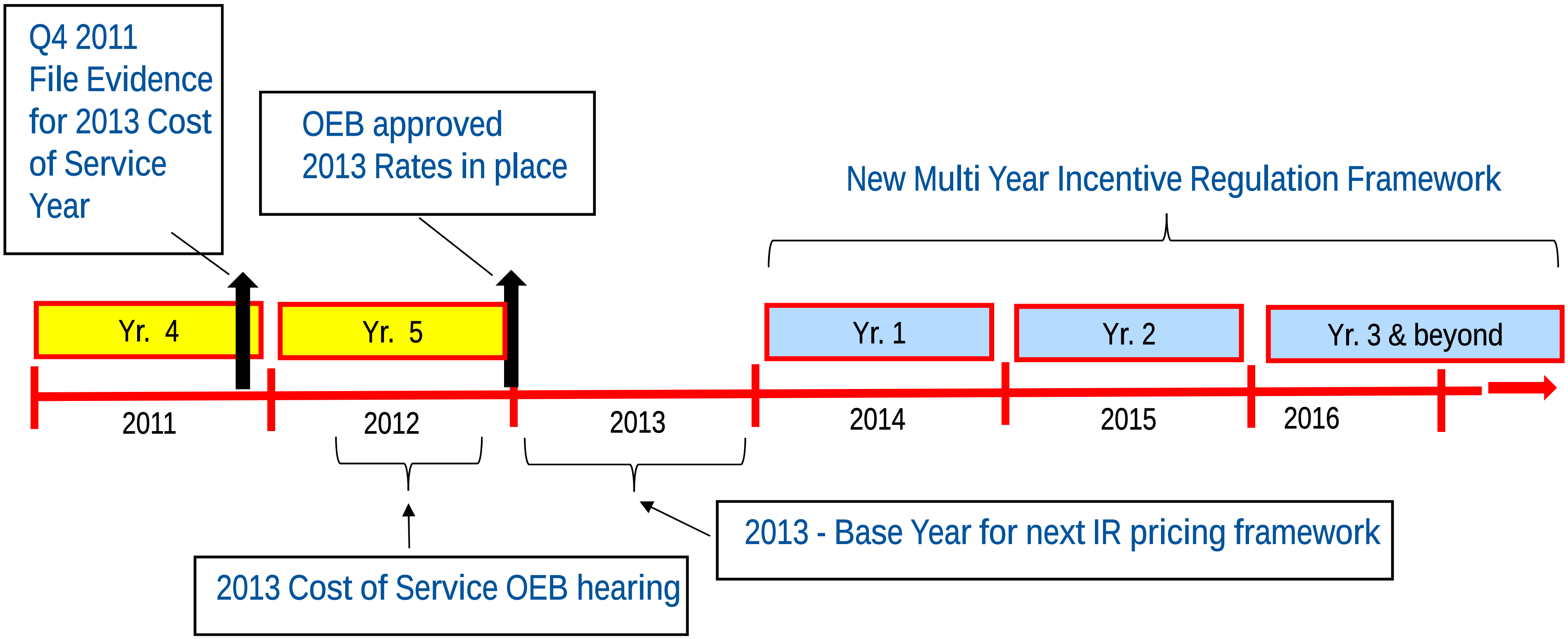
# Agenda

2013 Cost of Service Filing

Rate Design Proposals

- Bundled Contract Rate Eligibility (M4, M5A, M7)
- Rate T1 Redesign
  - Proposed New Rate T1 and Rate T2
- Elimination of Contract Rate Unbundled Service Offerings

# Looking Forward…



# Key Messages

- 2013 Cost of Service establishes new baseline for Board approved rates
- 2013 Contract Rate Class volume forecast recognizes impacts of global trends
  - Demand destruction (plant closures, energy efficiency)
  - Global competition (higher CDN $, international ownership)

# Rate Review Guidelines

Key Guidelines for appropriate rate design:

- Common profiles within rate classes
- Sufficient rate class size
- Sufficient differentiation among rate groupings
- Sufficient interest and reasonable prospect of use
- Rate harmonization

# Proposed M4, M5A and M7 Eligibility Changes

# Contract Service – Bundled For Rates M4 and M5A

| Rate Design Changes | Current Approved | Proposed |
|---|---|---|
| • Lower Union South bundled mid-market rate class eligibility | • Daily Contract Demand of 4,800 to 140,870 $m^3/d$ | • Daily Contract Demand of 2,400 to 60,000 $m^3/d$ |
| | | |
| | • Minimum Annual Volume of 700,000 $m^3$ | • Minimum Annual Volume of 350,000 $m^3$ |
| | | |
| | • Rate M4 load factor of at least 40% | • Rate M4 load factor of at least 40% |
| | | |
| • For Rate M4 Only | • Firm Contract Demand only | • Firm Contract Demand with Interruptible Option |

Proposed Implementation: January 1, 2014

# Contract Service – Bundled For Rate M7

| Rate Design Changes | Current Approved | Proposed |
|---|---|---|
| • Lower Union South bundled large volume rate class eligibility | • Combined Firm, Interruptible and Seasonal CD of at least 140,870 $m^3$/d | • Combined Contract Demand of at least 60,000 $m^3$/d |
| | • Annual Volume of at least 28,327,840 $m^3$ | • No MAV required for eligibility |
| | | |

Proposed Implementation: January 1, 2014

# Proposed Rate T1 Re-design

# Proposed Rate T1

| Rate Design Changes | Current Approved T1 | Proposed T1 |
|---|---|---|
| • Split Current T1 Class into T1 and T2 rate classes | • 5,000,000 $m^3$ Qualifying Annual Volume | • 2,500,000 $m^3$ Qualifying Annual Volume |
| | | • Firm Contract Demand up to 140,870 $m^3/d$ |
| | •Two Firm Contract Demand Blocks | • Two Firm Contract Demand Blocks |
| | • First 140,870 $m^3/d$<br>• All Over 140,870 $m^3/d$ | • First 28,150 $m^3/d$<br>• Next 112,720 $m^3/d$ |
| | • Two Firm Commodity blocks | • Single Firm Commodity rate |
| | • First 2,360,653 $m^3$<br>• All Over 2,360,653 $m^3$ | |
| • Monthly Customer charge per delivery point | • $1,795.31 | • $1,998.83 |

Proposed Implementation: January 1, 2013

# Proposed Rate T2

| Rate Design Changes | Current Approved T1 | Proposed T2 |
|---|---|---|
| • Split Current T1 Class into T1 and T2 rate classes | • 5,000,000 $m^3$ Qualifying Annual Volume | |
| | | • Firm daily Contract Demand of at least 140,870 $m^3/d$ |
| | • Two Firm Contract Demand Blocks | • Two Firm Contract Demand Blocks |
| | • First 140,870 $m^3/d$<br>• All Over 140,870 $m^3/d$ | • First 140,870 $m^3/d$<br>• All Over 140,870 $m^3/d$ |
| | • Two Firm Commodity blocks | • Single Firm Commodity rate |
| | • First 2,360,653 $m^3$<br>• All Over 2,360,653 $m^3$ | |
| • Monthly Customer charge per delivery point | • $1,795.31 | • $6,000 |

Proposed Implementation: January 1, 2013

# Elimination of Contract Rate Unbundled Service Offerings

- Union South – Rates U5, U7 and U9
- Union North – Rate 20 and Rate 100 Unbundled Services
- Rate schedules have been available for over ten years with no customers contracting for the services
- No customers forecasted in 2013 to utilize these services

Proposed Elimination: January 1, 2013

# Questions

UNION GAS LIMITED

Undertaking of Mr. Brett
To Mr. Shorts

Please explain how much direct purchase gas in Union's Southern Operating region carries an obligation to deliver to Parkway.

---

| | 2011/2012 | 2012/2013 | 2013/2014 |
|---|---|---|---|
| Direct Purchase | | | |
| Parkway | 67% | 67% | 67% |
| Dawn | 33% | 33% | 33% |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Shorts

Please identify Empress-to-Eastern Zone contracts turned back as of November 1, 2010, November 1, 2011 and November 1, 2012.

---

Please see the response at Exhibit JT1.9.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Shorts

To the extent that Union has FT RAM revenue, please provide capacity assignments or the costs associated with any of the capacity if netted against those revenues?

---

The capacity assignments included in Attachment 1 of J.C-4-7-10 are all temporary assignments. These assignments include 2 types of transactions – capacity assignments for unabsorbed demand charge (UDC) mitigation and capacity assignments related to FTRAM activities.

In the case where Union has assigned capacity to mitigate UDC, Union does not purchase the supply associated with the pipe capacity, and any revenue earned from the capacity assignment is credited to ratepayers.

In the case where Union has assigned capacity related to FTRAM activities, Union continues to purchase the supply attributable to the assigned capacity and utilizes exchanges or interruptible transportation to deliver the gas supply to Union's franchise (see examples at exhibit JT1-6). There is no change to transportation charges. Any associated revenue from the assignments, less the costs of exchanges or interruptible transportation are reflected in the net revenue from FTRAM. This is included at Exhibit JC-4-7-9, Attachment 2.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Tetreault

Please clarify the number and whether it includes space deemed unavailable and, if so, what amount.

---

The total working capacity of 164.8 PJ does not include space deemed unavailable.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Tetreault

Please update the Tables to include the C1 volumes if they were inadvertently omitted.

---

For the table at Exhibit J.G-10-10-1 c), the first line labeled "M12" includes C1 LT Firm volumes. This should be labeled "M12 + C1 LT Firm".

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Tetreault

Please update the tables and show the winter peaking costs that are consistent with the term in A. To confirm, if it is 2007/2008, what the cost was associated with the peaking service for that season, as opposed to the calendar-year cost.

---

| Winter | ($000's) |
|---|---|
| 2007/2008 | 2,724 |
| 2008/2009 | 95 |
| 2009/2010 | 5,727 |
| 2010/2011 | 4,087 |
| 2011/2012 | -- |

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Tetreault

Please explain why M12X is not included in volumes requiring Parkway compression.

---

In the response to J.G-10-10-5, parts a) and b), the M12X quantities included at line 7 should be included in the response as contracts that require Parkway compression.

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Tetreault

**H. RATE DESIGN**

1. Ref: Ex. J.H-1-1-2

The response notes that the increase in Union North delivery rates based on Union's updated evidence is about 20% and the increase in Union South delivery rates is about 7%. Page 4 of the response provides a number of rate mitigation measures that could be used to reduce these figures.

a) Please provide the comparable figures to the 20% and 7% increases noted above if the equity component of the capital structure were to be increased from 36% to 40% in equal increments over a 4 year period.
b) Please provide the comparable figures to the 20% and 7% increases noted above if the weather normalization methodology were to be phased in over a a 5 year period in equal increments.
c) Please provide the comparable figures to the 20% and 7% increases noted above if both of the phase-ins noted in (a) and (b) above were implemented.
d) Does the projected loss of the FT-RAM affect only Union North delivery rates?
e) Would Union agree to the establishment of a deferral/variance account to record any FT-RAM revenues received in 2013 that could be rebated to customers? If not, why not?
f) Please show the impact on revenue to cost ratios of the proposal noted on page 5 for each rate class in the North and South.

2. Ref: Ex. J.H-3-3-3 & Ex. J.H-14-2, Attachment 1

a) How did Union arrive at a monthly customer charge reduction from $70 to $35 per month?
b) Please provide a version of Attachment 1 of Exhibit J.H-14-2 that shows the bill impacts if the monthly customer charge for rates M2 and 10 is set at levels of $25 and $30 per month instead of $35 per month. Please also reflect the impact of the higher delivery (volumetric) rates that would be required to ensure revenue neutrality for the classes.
c) Has Union considered a phase-in approach to the monthly customer charge for Rate M2 and 10 customers to mitigate the impacts on the smaller volume customers in these classes? If not, why not?

3. Ref: Ex. J-H-5-2-1

The response shows that for customers with a load factor of 40% and a firm CD of 2,400 or 3,600 $m^3$ that Rate M4 would be more expensive than rate M2.

a) Based on a monthly customer charge for Rate M2 of $25 or $30 and the resulting increases in the variable rate requested in the previous technical conference question, please provide a version of Attachment 1 to Exhibit J.H-5-2-1 for each of the monthly customer charges.
b) Based on Union's proposal as shown in Attachment 1, what is the annual volume needed to make the costs under Rates M2 and M4 equivalent for a firm contract demand of 2,400 m3? for a firm contract demand of 3,600 $m^3$?

4. Ref: Ex. J.H-5-11-1

Please confirm that the 140 days use of firm contract demand noted on the first line of page 2 should be 146 days of firm contract demand.

5. Ref: Ex. J.H-10-2-1

The response indicates, that for billing purposes a number of M1 accounts cannot be grouped to become an M2 account and that a number of M2 accounts cannot be grouped to become an M4 account. The responses to part (k) and (l) appear to indicate that a customer with M1 and M2 accounts can aggregate them into an M2 account and a customer with M1 or M2 and an M4 account can aggregate them into an M4 contract.

a) Is the above correct?
b) Is a single meter required to aggregate these accounts for billing purposes?

6. Ref: Ex. J.H-10-2-1

With respect to part (q) of the response, Union indicates that it does offer a similar supplemental service under rates 01 and 10 but that there is no additional service charge for each additional meter.

a) Does the supplemental service available to rates 01 and 10 allow the volumes of the accounts combined to take advantage of the lower rates for higher volume blocks as does the M1 and M2 supplemental service?
b) Why is Union charging a service charge for each additional meter in Rates M1 and M2 but not for Rates 01 and 10?

---------------------------------------------------------------------------------------------------------------

1.

   a) In J.H-1-1-2 part c) Union stated that the revenue requirement impact associated with the increase in equity component of its capital structure from 36% to 40% was approximately $15 million.

      As per Exhibit E1, Tab 1, Updated, Page 2, Footnote 1, the actual revenue requirement impact associated with the increase in equity component of Union’s capital structure from 36% to 40% is $17.3 million.

Union has assumed an increase in the equity component of its capital structure from 36% to 37% in 2013. The revenue requirement impact associated with a 1% increase in equity thickness is approximately $4.3 million.

Based on a revenue requirement impact of $4.3 million versus $17.3 million, Union North delivery rates would increase by an average of 18.3% and Union South delivery rates would increase by an average of 5.6%.

b) As described in J.H-1-1-2 part c) Union's proposal to change its weather normalization method from the current 55:45 method to 100% 20-year declining trend increases its revenue deficiency by approximately $7 million.

   Union has assumed that the change in the weather normalization method is implemented over five years. The revenue deficiency impact associated with a five year phase-in is approximately $1.4 million in 2013.

   Based on a revenue deficiency impact of $1.4 million versus $7 million, Union North delivery rates would increase by an average of 18.6% and Union South delivery rates would increase by an average of 6.2%.

c) Based on the revenue requirement and revenue deficiency impacts described in parts a) and b) above combined, Union North delivery rates would increase by an average of 16.8% and Union South delivery rates would increase by an average of 4.9%.

d) No, the projected loss of the FT-RAM does not affect Union North delivery rates only.

e) As described in J.H-1-1-2 part c), Union has considered a partial rate mitigation measure whereby FT-RAM revenue is included in Union North delivery rates. Union would require deferral account protection to manage the possibility that the FT-RAM program is eliminated or changed materially in TCPL's NEB rate proceeding.

f) Union has derived revenue to cost ratios based on achieving a $31 bill increase for both Rate 01 and Rate M1 general service customers only. To achieve a $31 bill increase approximately $13 million in revenue was shifted from Rate 01 to Rate M1.

   Based on the assumptions above, the revenue to cost ratio in Rate 01 decreases from 0.984 to 0.904. The revenue to cost ratio in Rate M1 increases from 1.001 to 1.033.

2.

a) Union arrived at the proposed 2014 monthly customer charge of $35 for Rate 10 and Rate M2 by taking the approximate mid-point of the monthly customer charges required to recover all customer-related costs.

Table 1

Setting the 2014 Monthly Customer Charge
for Rate 10 and Rate M2

| Line No. | Particulars ($000's) | Rate 10 | Rate M2 |
|---|---|---|---|
| | | (a) | (b) |
| 1 | Customer-Related Costs | 10,527 | 22,006 |
| 2 | Annual Billing Units | 254,880 | 730,658 |
| 3 | Monthly Customer Charge | $ 41.30 | $ 30.12 |

b) Please see Attachment 1 showing the bill impacts and corresponding rates if the monthly customer charge for Rate 10 and Rate M2 is set at $25 per month.

Please see Attachment 2 showing the bill impacts and corresponding rates if the monthly customer charge for Rate 10 and Rate M2 is set at $30 per month.

c) No, Union has set the monthly customer charge for Rate 10 and Rate M2 customers to recover a reasonable proportion of the fixed costs allocated to these rate classes.

3.

a) Please see Attachment 3 showing the Rate M2 and Rate M4 comparison with a 2014 Rate M2 monthly customer charge set at $25.

Please see Attachment 4 showing the Rate M2 and Rate M4 comparison with a 2014 Rate M2 monthly customer charge set at $30.

b) For a firm contract demand of 2,400 $m^3$, the annual volume that makes the Rate M2 and Rate M4 costs equivalent is 382,593 $m^3$ (or a load factor of about 43.7%).

For a firm contract demand of 3,600 $m^3$, the annual volume that makes the Rate M2 and Rate M4 costs equivalent is 595,505 $m^3$ (or a load factor of about 45.3%).

4. Confirmed.

5.

a) Yes.

b) No.

6.

a) Yes.

b) The practice of combining meter readings from several meters for eligible Rate 01 and Rate 10 customers without charging the additional service charge has not been harmonized between Union North and Union South.

Annual General Service Delivery Bill Impacts - Union North
of Proposed 2014 Change in Annual Volume Breakpoint
and Proposed 2014 Change in Delivery Volume Blocks
Monthly Customer Charge for Rate 10 set at a a level of $25

| Annual Volume | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ and current delivery blocks | | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ and proposed delivery blocks | | Bill Impacts | |
|---|---|---|---|---|---|---|
| | Rate 01 | Rate 10 | Rate 01 | Rate 10 | $ | % |
| 1,800 | 430.37 | | 429.70 | | (0.68) | -0.2% |
| 2,200 | 468.59 | | 467.26 | | (1.33) | -0.3% |
| 2,600 | 506.46 | | 504.63 | | (1.83) | -0.4% |
| 3,000 | 544.12 | | 541.81 | | (2.31) | -0.4% |
| 5,000 | 727.95 | | 726.41 | | (1.54) | -0.2% |
| 5,001 | 728.04 | | | 676.55 | (51.49) | -7.1% |
| 6,000 | 818.50 | | | 751.77 | (66.73) | -8.2% |
| 7,000 | 907.92 | | | 826.99 | (80.93) | -8.9% |
| 10,000 | 1,173.21 | | | 1,048.93 | (124.27) | -10.6% |
| 20,000 | 2,047.14 | | | 1,781.44 | (265.69) | -13.0% |
| 30,000 | 2,915.26 | | | 2,509.94 | (405.32) | -13.9% |
| 50,000 | 4,646.89 | | | 3,959.82 | (687.07) | -14.8% |
| 60,000 | | 4,714.43 | | 4,652.63 | (61.81) | -1.3% |
| 70,000 | | 5,329.49 | | 5,334.31 | 4.82 | 0.1% |
| 80,000 | | 5,919.86 | | 6,010.33 | 90.47 | 1.5% |
| 100,000 | | 7,063.31 | | 7,355.65 | 292.34 | 4.1% |
| 200,000 | | 12,622.44 | | 13,671.72 | 1,049.28 | 8.3% |
| 300,000 | | 17,828.31 | | 19,546.85 | 1,718.54 | 9.6% |
| 500,000 | | 27,842.19 | | 30,980.13 | 3,137.95 | 11.3% |

UNION GAS LIMITED
Union North - Summary of Proposed 2013 and 2014 General Service Delivery Rates
including 2014 Annual Volume Breakpoint and Rate Structure Redesign

| Line No. | Particulars (2013 Proposed) | Annual Billing Units ($10^3m^3$) (a) | Revenue ($000's) (b) | Rates (cents/$m^3$) (c) | Particulars (2014 Proposed) | Annual Billing Units ($10^3m^3$) (d) | Revenue ($000's) (e) | Rates (cents/$m^3$) (f) |
|---|---|---|---|---|---|---|---|---|
| | **Proposed 2013 Rate 01 Delivery** | | | | **Proposed 2014 Rate 01 Delivery** | | | |
| 1 | Monthly Charge | 3,832,876 | 80,490 | $21.00 | Monthly Charge | 3,602,569 | 75,654 | $21.00 |
| | Monthly Delivery Charge | | | | Monthly Delivery Charge | | | |
| 2 | First 100 $m^3$ per month | 253,052 | 25,720 | 10.1637 | First 100 $m^3$ per month | 231,257 | 23,411 | 10.1235 |
| 3 | Next 200 $m^3$ per month | 285,237 | 27,495 | 9.6392 | Next 150 $m^3$ per month | 262,760 | 25,472 | 9.6941 |
| 4 | Next 200 $m^3$ per month | 124,436 | 11,531 | 9.2665 | All Over 250 $m^3$ per month | 165,752 | 15,075 | 9.0949 |
| 5 | Next 500 $m^3$ per month | 85,489 | 7,630 | 8.9245 | | | | |
| 6 | Over 1,000 $m^3$ per month | 107,383 | 9,280 | 8.6420 | | | | |
| 7 | Total 2013 Rate 01 Delivery | 855,598 | 162,145 | | Total 2014 Rate 01 Delivery | 659,769 | 139,612 | |
| | **Proposed 2013 Rate 10 Delivery** | | | | **Proposed 2014 Rate 10 Delivery** | | | |
| 8 | Monthly Charge | 24,573 | 1,720 | $70.00 | Monthly Charge | 254,880 | 6,372 | $25.00 |
| | Monthly Delivery Charge | | | | Monthly Delivery Charge | | | |
| 9 | First 1,000 $m^3$ per month | 23,230 | 1,763 | 7.5883 | First 1,000 $m^3$ per month | 188,187 | 14,170 | 7.5295 |
| 10 | Next 9,000 $m^3$ per month | 125,165 | 7,729 | 6.1747 | Next 6,000 $m^3$ per month | 152,274 | 11,058 | 7.2618 |
| 11 | Next 20,000 $m^3$ per month | 79,608 | 4,274 | 5.3685 | Next 13,000 $m^3$ per month | 63,469 | 4,119 | 6.4901 |
| 12 | Next 70,000 $m^3$ per month | 60,460 | 2,934 | 4.8524 | All Over 20,000 $m^3$ per month | 108,167 | 6,039 | 5.5828 |
| 13 | Over 100,000 $m^3$ per month | 27,805 | 806 | 2.8972 | | | | |
| 14 | Total 2013 Rate 10 Delivery | 316,269 | 19,224 | | Total 2014 Rate 10 Delivery | 512,098 | 41,757 | |
| 15 | Total 2013 General Service Delivery | 1,171,866 | 181,370 | | Total 2014 General Service Delivery | 1,171,866 | 181,370 | |

Annual General Service Delivery Bill Impacts - Union South
of Proposed 2014 Change in Annual Volume Breakpoint
Monthly Customer Charge for Rate M2 set at a a level of $25

| Annual Volume | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ Rate M1 | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ Rate M2 | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ Rate M1 | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ Rate M2 | Bill Impacts $ | Bill Impacts % |
|---|---|---|---|---|---|---|
| 1,800 | 327.69 | | 328.98 | | 1.29 | 0.4% |
| 2,200 | 343.16 | | 344.58 | | 1.42 | 0.4% |
| 2,600 | 358.55 | | 360.08 | | 1.53 | 0.4% |
| 3,000 | 373.82 | | 375.47 | | 1.65 | 0.4% |
| 5,000 | 449.13 | | 451.34 | | 2.21 | 0.5% |
| 5,001 | 449.17 | | | 498.75 | 49.58 | 11.0% |
| 6,000 | 486.16 | | | 538.33 | 52.17 | 10.7% |
| 7,000 | 523.15 | | | 577.68 | 54.54 | 10.4% |
| 10,000 | 633.91 | | | 694.96 | 61.05 | 9.6% |
| 20,000 | 999.67 | | | 1,083.86 | 84.20 | 8.4% |
| 30,000 | 1,364.94 | | | 1,471.48 | 106.55 | 7.8% |
| 50,000 | 2,095.47 | | | 2,240.39 | 144.92 | 6.9% |
| 60,000 | | 3,316.76 | | 2,618.44 | (698.32) | -21.1% |
| 70,000 | | 3,717.42 | | 2,995.79 | (721.63) | -19.4% |
| 80,000 | | 4,117.07 | | 3,372.50 | (744.58) | -18.1% |
| 100,000 | | 4,911.88 | | 4,122.98 | (788.90) | -16.1% |
| 200,000 | | 8,736.83 | | 7,830.67 | (906.15) | -10.4% |
| 300,000 | | 12,470.81 | | 11,512.30 | (958.51) | -7.7% |
| 500,000 | | 19,846.07 | | 18,843.57 | (1,002.50) | -5.1% |

UNION GAS LIMITED
Union South - Summary of Proposed 2013 and 2014 General Service Delivery Rates
including 2014 Annual Volume Breakpoint Redesign

| Line No. | Particulars | 2013 Proposed Annual Billing Units ($10^3m^3$) (a) | 2013 Proposed Revenue ($000's) (b) | 2013 Proposed Rates (cents/$m^3$) (c) | 2014 Proposed Annual Billing Units ($10^3m^3$) (d) | 2014 Proposed Revenue ($000's) (e) | 2014 Proposed Rates (cents/$m^3$) (f) |
|---|---|---|---|---|---|---|---|
| | **Proposed Rate M1 Delivery** | | | | | | |
| 1 | Monthly Charge | 12,706,802 | 266,843 | $21.00 | 12,057,495 | 253,207 | $21.00 |
| | Monthly Delivery Charge | | | | | | |
| 2 | First 100 $m^3$ per month | 868,730 | 37,770 | 4.3477 | 807,714 | 36,232 | 4.4858 |
| 3 | Next 150 $m^3$ per month | 767,998 | 31,804 | 4.1412 | 703,930 | 29,080 | 4.1311 |
| 4 | All Over 250 $m^3$ per month | 1,239,684 | 45,282 | 3.6527 | 634,207 | 23,335 | 3.6794 |
| 5 | Total Rate M1 Delivery | 2,876,411 | 381,698 | | 2,145,851 | 341,855 | |
| | **Proposed Rate M2 Delivery** | | | | | | |
| 6 | Monthly Charge | 81,451 | 5,702 | $70.00 | 730,758 | 18,269 | $25.00 |
| | Monthly Delivery Charge | | | | | | |
| 7 | First 1,000 $m^3$ per month | 52,132 | 2,203 | 4.2259 | 461,452 | 18,339 | 3.9743 |
| 8 | Next 6,000 $m^3$ per month | 253,275 | 10,510 | 4.1496 | 571,592 | 22,101 | 3.8665 |
| 9 | Next 13,000 $m^3$ per month | 285,869 | 11,212 | 3.9222 | 288,792 | 10,739 | 3.7187 |
| 10 | All Over 20,000 $m^3$ per month | 365,375 | 13,334 | 3.6493 | 365,375 | 13,356 | 3.6553 |
| 11 | Total Rate M2 Delivery | 956,651 | 42,960 | | 1,687,211 | 82,804 | |
| 12 | Total General Service Delivery | 3,833,062 | 424,659 | | 3,833,062 | 424,659 | |

Annual General Service Delivery Bill Impacts - Union North
of Proposed 2014 Change in Annual Volume Breakpoint
and Proposed 2014 Change in Delivery Volume Blocks
Monthly Customer Charge for Rate 10 set at a level of $30

| | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ and current delivery blocks | | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ and proposed delivery blocks | | Bill Impacts | |
|---|---|---|---|---|---|---|
| Annual Volume | Rate 01 | Rate 10 | Rate 01 | Rate 10 | $ | % |
| 1,800 | 430.37 | | 429.70 | | (0.68) | -0.2% |
| 2,200 | 468.59 | | 467.26 | | (1.33) | -0.3% |
| 2,600 | 506.46 | | 504.63 | | (1.83) | -0.4% |
| 3,000 | 544.12 | | 541.81 | | (2.31) | -0.4% |
| 5,000 | 727.95 | | 726.41 | | (1.54) | -0.2% |
| 5,001 | 728.04 | | | 724.11 | (3.93) | -0.5% |
| 6,000 | 818.50 | | | 796.84 | (21.66) | -2.6% |
| 7,000 | 907.92 | | | 869.57 | (38.35) | -4.2% |
| 10,000 | 1,173.21 | | | 1,084.05 | (89.15) | -7.6% |
| 20,000 | 2,047.14 | | | 1,791.68 | (255.45) | -12.5% |
| 30,000 | 2,915.26 | | | 2,495.30 | (419.96) | -14.4% |
| 50,000 | 4,646.89 | | | 3,895.42 | (751.48) | -16.2% |
| 60,000 | | 4,714.43 | | 4,563.35 | (151.09) | -3.2% |
| 70,000 | | 5,329.49 | | 5,220.15 | (109.34) | -2.1% |
| 80,000 | | 5,919.86 | | 5,871.29 | (48.57) | -0.8% |
| 100,000 | | 7,063.31 | | 7,166.85 | 103.54 | 1.5% |
| 200,000 | | 12,622.44 | | 13,234.04 | 611.59 | 4.8% |
| 300,000 | | 17,828.31 | | 18,860.17 | 1,031.87 | 5.8% |
| 500,000 | | 27,842.19 | | 29,795.38 | 1,953.20 | 7.0% |

UNION GAS LIMITED
Union North - Summary of Proposed 2013 and 2014 General Service Delivery Rates
including 2014 Annual Volume Breakpoint and Rate Structure Redesign

| | 2013 Proposed | | | | 2014 Proposed | | | |
|---|---|---|---|---|---|---|---|---|
| Line No. | Particulars | Annual Billing Units ($10^3m^3$) | Revenue ($000's) | Rates (cents/$m^3$) | Particulars | Annual Billing Units ($10^3m^3$) | Revenue ($000's) | Rates (cents/$m^3$) |
| | | (a) | (b) | (c) | | (d) | (e) | (f) |
| | **Proposed 2013 Rate 01 Delivery** | | | | **Proposed 2014 Rate 01 Delivery** | | | |
| 1 | Monthly Charge | 3,832,876 | 80,490 | $21.00 | Monthly Charge | 3,602,569 | 75,654 | $21.00 |
| | Monthly Delivery Charge | | | | Monthly Delivery Charge | | | |
| 2 | First 100 $m^3$ per month | 253,052 | 25,720 | 10.1637 | First 100 $m^3$ per month | 231,257 | 23,411 | 10.1235 |
| 3 | Next 200 $m^3$ per month | 285,237 | 27,495 | 9.6392 | Next 150 $m^3$ per month | 262,760 | 25,472 | 9.6941 |
| 4 | Next 200 $m^3$ per month | 124,436 | 11,531 | 9.2665 | All Over 250 $m^3$ per month | 165,752 | 15,075 | 9.0949 |
| 5 | Next 500 $m^3$ per month | 85,489 | 7,630 | 8.9245 | | | | |
| 6 | Over 1,000 $m^3$ per month | 107,383 | 9,280 | 8.6420 | | | | |
| 7 | Total 2013 Rate 01 Delivery | 855,598 | 162,145 | | Total 2014 Rate 01 Delivery | 659,769 | 139,612 | |
| | **Proposed 2013 Rate 10 Delivery** | | | | **Proposed 2014 Rate 10 Delivery** | | | |
| 8 | Monthly Charge | 24,573 | 1,720 | $70.00 | Monthly Charge | 254,880 | 7,646 | $30.00 |
| | Monthly Delivery Charge | | | | Monthly Delivery Charge | | | |
| 9 | First 1,000 $m^3$ per month | 23,230 | 1,763 | 7.5883 | First 1,000 $m^3$ per month | 188,187 | 13,701 | 7.2807 |
| 10 | Next 9,000 $m^3$ per month | 125,165 | 7,729 | 6.1747 | Next 6,000 $m^3$ per month | 152,274 | 10,679 | 7.0130 |
| 11 | Next 20,000 $m^3$ per month | 79,608 | 4,274 | 5.3685 | Next 13,000 $m^3$ per month | 63,469 | 3,961 | 6.2413 |
| 12 | Next 70,000 $m^3$ per month | 60,460 | 2,934 | 4.8524 | All Over 20,000 $m^3$ per month | 108,167 | 5,769 | 5.3337 |
| 13 | Over 100,000 $m^3$ per month | 27,805 | 806 | 2.8972 | | | | |
| 14 | Total 2013 Rate 10 Delivery | 316,269 | 19,224 | | Total 2014 Rate 10 Delivery | 512,098 | 41,757 | |
| 15 | Total 2013 General Service Delivery | 1,171,866 | 181,370 | | Total 2014 General Service Delivery | 1,171,866 | 181,370 | |

Annual General Service Delivery Bill Impacts - Union South
of Proposed 2014 Change in Annual Volume Breakpoint
Monthly Charge for Rate M2 set at a level of $30

| Annual Volume | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ Rate M1 | Rate M2 | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ Rate M1 | Rate M2 | Bill Impacts $ | % |
|---|---|---|---|---|---|---|
| 1,800 | 327.69 | | 328.98 | | 1.29 | 0.4% |
| 2,200 | 343.16 | | 344.58 | | 1.42 | 0.4% |
| 2,600 | 358.55 | | 360.08 | | 1.53 | 0.4% |
| 3,000 | 373.82 | | 375.47 | | 1.65 | 0.4% |
| 5,000 | 449.13 | | 451.34 | | 2.21 | 0.5% |
| 5,001 | 449.17 | | | 547.93 | 98.76 | 22.0% |
| 6,000 | 486.16 | | | 585.34 | 99.18 | 20.4% |
| 7,000 | 523.15 | | | 622.53 | 99.38 | 19.0% |
| 10,000 | 633.91 | | | 733.31 | 99.40 | 15.7% |
| 20,000 | 999.67 | | | 1,100.56 | 100.90 | 10.1% |
| 30,000 | 1,364.94 | | | 1,466.53 | 101.60 | 7.4% |
| 50,000 | 2,095.47 | | | 2,192.14 | 96.67 | 4.6% |
| 60,000 | | 3,316.76 | | 2,548.54 | (768.22) | -23.2% |
| 70,000 | | 3,717.42 | | 2,904.24 | (813.17) | -21.9% |
| 80,000 | | 4,117.07 | | 3,259.30 | (857.78) | -20.8% |
| 100,000 | | 4,911.88 | | 3,966.48 | (945.40) | -19.2% |
| 200,000 | | 8,736.83 | | 7,457.55 | (1,279.28) | -14.6% |
| 300,000 | | 12,470.81 | | 10,922.48 | (1,548.33) | -12.4% |
| 500,000 | | 19,846.07 | | 17,820.28 | (2,025.79) | -10.2% |

UNION GAS LIMITED
Union South - Summary of Proposed 2013 and 2014 General Service Delivery Rates
including 2014 Annual Volume Breakpoint Redesign

| | | 2013 Proposed | | | 2014 Proposed | | |
|---|---|---|---|---|---|---|---|
| Line No. | Particulars | Annual Billing Units ($10^3m^3$) | Revenue ($000's) | Rates (cents/$m^3$) | Annual Billing Units ($10^3m^3$) | Revenue ($000's) | Rates (cents/$m^3$) |
| | | (a) | (b) | (c) | (d) | (e) | (f) |
| | **Proposed Rate M1 Delivery** | | | | | | |
| 1 | Monthly Charge | 12,706,802 | 266,843 | $21.00 | 12,057,495 | 253,207 | $21.00 |
| | Monthly Delivery Charge | | | | | | |
| 2 | First 100 $m^3$ per month | 868,730 | 37,770 | 4.3477 | 807,714 | 36,232 | 4.4858 |
| 3 | Next 150 $m^3$ per month | 767,998 | 31,804 | 4.1412 | 703,930 | 29,080 | 4.1311 |
| 4 | All Over 250 $m^3$ per month | 1,239,684 | 45,282 | 3.6527 | 634,207 | 23,335 | 3.6794 |
| 5 | Total Rate M1 Delivery | 2,876,411 | 381,698 | | 2,145,851 | 341,855 | |
| | **Proposed Rate M2 Delivery** | | | | | | |
| 6 | Monthly Charge | 81,451 | 5,702 | $70.00 | 730,758 | 21,923 | $30.00 |
| | Monthly Delivery Charge | | | | | | |
| 7 | First 1,000 $m^3$ per month | 52,132 | 2,203 | 4.2259 | 461,452 | 17,340 | 3.7578 |
| 8 | Next 6,000 $m^3$ per month | 253,275 | 10,510 | 4.1496 | 571,592 | 20,863 | 3.6500 |
| 9 | Next 13,000 $m^3$ per month | 285,869 | 11,212 | 3.9222 | 288,792 | 10,114 | 3.5022 |
| 10 | All Over 20,000 $m^3$ per month | 365,375 | 13,334 | 3.6493 | 365,375 | 12,564 | 3.4385 |
| 11 | Total Rate M2 Delivery | 956,651 | 42,960 | | 1,687,211 | 82,804 | |
| 12 | Total General Service Delivery | 3,833,062 | 424,659 | | 3,833,062 | 424,659 | |

Annual Delivery Bill Impacts - Union South
Customers in Rate M2 in 2014 moving to Rate M4 in 2014
based on a 2014 Rate M2 Customer Charge at a level of $25

| | Firm Contract Demand ($m^3$/day) | Annual Volume ($m^3$) | Load Factor | 2013 Proposed Rate M2 (1) | 2013 Proposed Rate M4 | 2014 Proposed Rate M2 | 2014 Proposed Rate M4 (2) | Bill Impacts $ | Bill Impacts % |
|---|---|---|---|---|---|---|---|---|---|
| i) | 2,400 | 350,000 | 0.40 | 17,246.01 | | 16,267.93 | 18,362.00 | 2,094.07 | 12.9% |
| ii) | 2,400 | 500,000 | 0.57 | 24,015.08 | | 23,012.57 | 20,017.14 | (2,995.44) | -13.0% |
| iii) | 3,600 | 525,600 | 0.40 | 25,169.04 | | 24,163.24 | 27,549.62 | 3,386.37 | 14.0% |
| iv) | 3,600 | 650,000 | 0.49 | 30,776.56 | | 29,754.79 | 28,922.28 | (832.51) | -2.8% |

Notes:

(1) Includes impact of the 2013 proposed Rate M2 storage rate of 0.8338 cents/$m^3$.

(2) Based on parameters provided, all contract demand in first block demand and all throughput volume in first block commodity.

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JT2.18
Attachment 4

Annual Delivery Bill Impacts - Union South
Customers in Rate M2 in 2014 moving to Rate M4 in 2014
based on a 2014 Rate M2 Customer Charge at a level of $30

| | Firm Contract Demand ($m^3$/day) | Annual Volume ($m^3$) | Load Factor | 2013 Proposed Rate M2 (1) | 2013 Proposed Rate M4 | 2014 Proposed Rate M2 | 2014 Proposed Rate M4 (2) | Bill Impacts $ | Bill Impacts % |
|---|---|---|---|---|---|---|---|---|---|
| i) | 2,400 | 350,000 | 0.40 | 17,246.01 | | 15,569.75 | 18,362.00 | 2,792.25 | 17.9% |
| ii) | 2,400 | 500,000 | 0.57 | 24,015.08 | | 21,989.28 | 20,017.14 | (1,972.15) | -9.0% |
| iii) | 3,600 | 525,600 | 0.40 | 25,169.04 | | 23,084.47 | 27,549.62 | 4,465.15 | 19.3% |
| iv) | 3,600 | 650,000 | 0.49 | 30,776.56 | | 28,406.38 | 28,922.28 | 515.89 | 1.8% |

Notes:

(1) Includes impact of the 2013 proposed Rate M2 storage rate of 0.8338 cents/$m^3$.

(2) Based on parameters provided, all contract demand in first block demand and all throughput volume in first block commodity.

UNION GAS LIMITED

Undertaking of Mr. Gruenbauer
To Mr. Tetreault

Please duplicate J.H-1-8-1, Attachment 2 for using Rate T1 and T2.

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Please see the Attachment.

Summary of Customer-Related Costs Allocated to Proposed Rate T1/Rate T2 and Rate T3
2007 Board-Approved vs. 2013 Proposed Cost Allocation Study

| Line No. | Particulars ($000's) | 2007 | 2013 T1 | 2013 T2 | 2013 T3 | 2013 Total | Difference | Proposed Methodology Changes: Meter and Regulator Repairs | Proposed Methodology Changes: Equipment on Customer Premises | Difference less Methodology Changes |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e)=(b+c+d) | (f) = (e - a) | (g) | (h) | (i) = (f - g - h) |
| | T1/T2 Customer-Related Costs | | | | | | | | | |
| 1 | Return and Taxes | 758 | 303 | 2,942 | - | 3,245 | 2,487 | 4 | 2 | 2,481 |
| 2 | Depreciation Expense | 465 | 216 | 1,719 | - | 1,935 | 1,470 | 8 | 4 | 1,457 |
| | Operating Expenses | | | | | | | | | |
| 3 | Distribution (Southern Ontario) | 109 | 63 | 587 | - | 650 | 540 | 117 | 63 | 360 |
| 4 | General Operating & Engineering | 75 | 35 | 346 | - | 381 | 307 | (0) | 0 | 307 |
| 5 | Sales Promotion and Merchandise | 92 | 362 | 333 | - | 695 | 604 | 0 | 0 | 604 |
| 6 | Distribution Customer Accounting | 137 | 27 | 56 | - | 83 | (54) | 0 | 0 | (54) |
| 7 | Administrative & General | 233 | 415 | 1,077 | - | 1,493 | 1,260 | 103 | 56 | 1,101 |
| 8 | Total T1/T2 Revenue Requirement | 1,867 | 1,421 | 7,060 | - | 8,482 | 6,614 | 231 | 126 | 6,257 |
| | T3 Customer-Related Costs (1) | | | | | | | | | |
| 1 | Return and Taxes | 68 | - | - | 61 | 61 | (6) | 0 | 0 | (7) |
| 2 | Depreciation Expense | 50 | - | - | 52 | 52 | 2 | 1 | 0 | 0 |
| | Operating Expenses | | | | | | | | | |
| 3 | Distribution (Southern Ontario) | 0 | - | - | 15 | 15 | 15 | 10 | 5 | 0 |
| 4 | General Operating & Engineering | 7 | - | - | 7 | 7 | 0 | 0 | 0 | 0 |
| 5 | Sales Promotion and Merchandise | 45 | - | - | 54 | 54 | 9 | 0 | 0 | 9 |
| 6 | Distribution Customer Accounting | 2 | - | - | 1 | 1 | (0) | 0 | 0 | (0) |
| 7 | Administrative & General | 34 | - | - | 68 | 68 | 35 | 9 | 5 | 21 |
| 8 | Total T3 Revenue Requirement | 206 | - | - | 259 | 259 | 54 | 19 | 10 | 24 |

Note:
(1) As provided at J.H-1-8-1, Attachment 2.

UNION GAS LIMITED

Undertaking of Mr. Wolnik
To Mr. Tetreault

Please explain why non-utility customers are not subject to empty space hysteresis.

---

Empty space for hysteresis is not required for non-utility customers as these customers only have firm injections rights available if they have empty contracted space.

UNION GAS LIMITED

Undertaking of Mr. Wolnik
To Mr. Tetreault

Reference: J.H.-1-13-1, J.H.-1-1-2

In the first reference Union was asked to provide a detailed explanation to support the increases for Rate classes 20, 25 and 100 of 43.5%, 43.4% and 29.1% respectively. These increases are relative to the rates currently in effect. Union's response was to see the response to J.H.-1.1.2 a) J.H.-1.1.2a). These responses provide general aggregate information about revenue requirement in the North and limit the comparison to changes from 2007, and do not provide any rate specific information for the rates requested.

a) Please provide a detailed explanation by rate class for these significant rate increases as requested. Please include (but do not limit the response to) the impact of the following items in explaining the overall increases:

   i) Forecast volumes by rate class.
   ii) The impact by rate class of the increase in rate of return.
   iii) The impact by rate class of the increase in the additional equity.
   iv) The impact by rate class of the $22.7 increase in O&M from 2007 (see Attachment 1 to J.H.-1-1-2 line 10).
   v) The impact by rate class of Union's elimination of the FT-Ram Credits.
   vi) Changes by rate class referenced in G1 Tab 1 pages 11-15.
   vii) The impacts of DSM programs by rate class (include both the program costs and lost revenue impacts).
   viii) The impact by rate class of proposed changes to depreciation expense.

---

The Union North revenue requirement increase is driven by cost increases and cost allocation corrections since the 2007 Board-approved cost allocation study. A comparison between the 2007 Board-approved and the 2013 proposed cost allocation study by Union North rate class is provided at Attachment 1.

In J.H-1-1-2, part a), pages 3-4, Union provides a description of the drivers for the Union North revenue requirement increase, which includes local storage plant, distribution depreciation expense, distribution O&M, sales and promotion O&M and general operating and engineering O&M. The total revenue requirement increase to Union North rate classes for each of the cost drivers is provided at lines 1, 8, 12, 13, and 14, respectively on Attachment 1. The revenue requirement increase associated with interest and return by rate class is provided on lines 4 and 5 and the increase in Union North depreciation expense by rate class is provided at line 10.

The $22.7 million increase in O&M in J.H-1-1-2, line 10, is the delivery-related revenue requirement for the Union North rate classes. The total Union North O&M increase of $24.3

million is provided at line 17 and includes the allocation of administrative and general O&M expense. Administrative and general costs are allocated in proportion to the allocation of other O&M expenses in the cost allocation study. As both Union North O&M and total administrative and general O&M costs have increased from Board-approved 2007 levels, the allocation of administrative and general O&M costs to Union North rate classes have increased, as provided at line 15.

Union has also proposed several cost allocation methodology changes that impact the allocation to Union North rate classes. The revenue requirement impact of those changes by rate class is provided at J.G-1-3-1, Attachment 2.

Union North rate classes are also impacted by customer changes by rate class. The 2013 forecasted number of customers, contracted demands, and annual volumes relative to 2007 and 2011 Board-approved levels are provided at Attachment 2. The impact of DSM program cost changes by Union North rate class relative to 2007 and 2011 Board-approved levels are provided at Attachment 3.

FT-RAM revenue was not included in either 2007 Board-approved rates or 2013 proposed rates and accordingly is not driving an increase in Union North rates.

Union North In-franchise Revenue Requirment Comparison by Rate Class
Filed 2013 vs. 2007 Board-Approved Cost Study

| Line | | 2007 | | | | | | 2013 | | | | | | 2013 less 2007 Board-Approved | | | | | Variance | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Particulars ($000's) | R01 | R10 | R20 | R100 | R25 | Total | R01 | R10 | R20 | R100 | R25 | Total | R01 | R10 | R20 | R100 | R25 | Total | % |
| | | (a) | (b) | (c) | (d) | (e) | (f)=(a+b+c+d+e) | (g) | (h) | (i) | (j) | (k) | (l)=(g+h+i+j+k) | (m)=(g-a) | (n)=(h-b) | (o)=(i-c) | (p)=(j-d) | (q)=(k-e) | (r)=(l-f) | (s)=((l-f)/f) |
| | Net Plant | | | | | | | | | | | | | | | | | | | |
| 1 | Local Storage Plant [(1)] | 1,585 | 507 | 61 | 83 | 0 | 2,236 | 8,622 | 2,282 | 601 | 42 | 0 | 11,547 | 7,038 | 1,775 | 540 | (41) | 0 | 9,311 | 416% |
| 2 | Other Rate Base [(2)] | 559,965 | 103,279 | 53,674 | 71,026 | 24,119 | 812,062 | 654,965 | 91,608 | 74,667 | 56,888 | 24,780 | 902,907 | 95,000 | (11,671) | 20,993 | (14,138) | 661 | 90,844 | 11% |
| 3 | Total Rate Base | 561,550 | 103,786 | 53,736 | 71,109 | 24,119 | 814,298 | 663,587 | 93,890 | 75,268 | 56,930 | 24,780 | 914,454 | 102,037 | (9,896) | 21,532 | (14,179) | 661 | 100,156 | 12% |
| 4 | Return - Debt Component | 26,433 | 4,885 | 2,529 | 3,347 | 1,135 | 38,331 | 25,772 | 3,646 | 2,923 | 2,211 | 962 | 35,515 | (662) | (1,239) | 394 | (1,136) | (173) | (2,816) | (7%) |
| 5 | Equity Component | 18,116 | 3,348 | 1,734 | 2,294 | 778 | 26,270 | 25,990 | 3,677 | 2,948 | 2,230 | 971 | 35,815 | 7,874 | 329 | 1,214 | (64) | 192 | 9,546 | 36% |
| 6 | Taxes | 19,131 | 3,423 | 1,607 | 2,037 | 703 | 26,900 | 16,767 | 2,513 | 1,939 | 1,580 | 578 | 23,377 | (2,364) | (911) | 332 | (457) | (125) | (3,523) | (13%) |
| 7 | Total Return and Taxes | 63,680 | 11,657 | 5,870 | 7,678 | 2,616 | 91,501 | 68,529 | 9,836 | 7,810 | 6,021 | 2,511 | 94,707 | 4,849 | (1,821) | 1,940 | (1,657) | (105) | 3,206 | 4% |
| | Depreciation Expense | | | | | | | | | | | | | | | | | | | |
| 8 | Union North Distribution Plant [(3)] | 23,653 | 3,644 | 2,328 | 3,248 | 1,199 | 34,072 | 29,444 | 3,714 | 3,424 | 3,093 | 1,221 | 40,896 | 5,791 | 69 | 1,097 | (155) | 22 | 6,824 | 20% |
| 9 | Other Depreciation Plant | 7,033 | 1,246 | 595 | 714 | 213 | 9,802 | 9,609 | 1,586 | 949 | 591 | 282 | 13,016 | 2,575 | 340 | 353 | (123) | 69 | 3,214 | 33% |
| 10 | Total Depreciation Expense | 30,686 | 4,890 | 2,923 | 3,962 | 1,412 | 43,874 | 39,053 | 5,299 | 4,373 | 3,684 | 1,503 | 53,912 | 8,367 | 409 | 1,450 | (278) | 91 | 10,038 | 23% |
| 11 | Cost of Gas [(4)] | 200,362 | 58,275 | 13,444 | 2,441 | 13,760 | 288,283 | 145,807 | 41,021 | 8,747 | 46 | 8,031 | 203,652 | (54,555) | (17,255) | (4,697) | (2,396) | (5,728) | (84,631) | (29%) |
| | O&M | | | | | | | | | | | | | | | | | | | |
| 12 | Distribution North [(5)] | 12,943 | 1,544 | 1,137 | 2,304 | 332 | 18,260 | 16,137 | 1,653 | 1,874 | 1,837 | 656 | 22,157 | 3,194 | 109 | 736 | (467) | 324 | 3,896 | 21% |
| 13 | Sales and Promotion [(6)] | 2,904 | 1,392 | 1,024 | 1,584 | 55 | 6,959 | 5,924 | 1,294 | 1,395 | 2,053 | 439 | 11,105 | 3,020 | (98) | 371 | 468 | 384 | 4,145 | 60% |
| 14 | General Operating & Engineering [(7)] | 4,730 | 642 | 401 | 365 | 235 | 6,373 | 7,225 | 854 | 919 | 608 | 368 | 9,973 | 2,494 | 211 | 518 | 243 | 134 | 3,600 | 56% |
| 15 | Administrative and General | 20,780 | 2,254 | 1,390 | 2,066 | 438 | 26,929 | 31,919 | 2,824 | 2,640 | 2,177 | 1,215 | 40,775 | 11,139 | 570 | 1,249 | 111 | 777 | 13,846 | 51% |
| 16 | Other O&M | 16,081 | 1,291 | 231 | 165 | 187 | 17,955 | 15,254 | 1,107 | 247 | 31 | 121 | 16,761 | (827) | (184) | 16 | (134) | (66) | (1,194) | (7%) |
| 17 | Total O&M | 57,439 | 7,123 | 4,184 | 6,483 | 1,247 | 76,476 | 76,460 | 7,731 | 7,074 | 6,706 | 2,799 | 100,771 | 19,021 | 608 | 2,890 | 223 | 1,552 | 24,294 | 32% |
| 18 | Total Revenue Requirement | 352,167 | 81,946 | 26,420 | 20,565 | 19,035 | 500,133 | 329,848 | 63,887 | 28,004 | 16,457 | 14,845 | 453,042 | (22,319) | (18,058) | 1,584 | (4,108) | (4,190) | (47,092) | (9%) |
| 19 | Other Revenue | 5,708 | 60 | 1 | 0 | 1 | 5,770 | 5,490 | 43 | 1 | 0 | 1 | 5,535 | (218) | (17) | 0 | (0) | 0 | (234) | (4%) |
| 20 | Total Revenue Requirement (line 18 - line 19) | 346,459 | 81,886 | 26,419 | 20,565 | 19,035 | 494,364 | 324,358 | 63,844 | 28,003 | 16,457 | 14,844 | 447,506 | (22,101) | (18,042) | 1,584 | (4,108) | (4,191) | (46,857) | -9% |
| | Revenue Requirement in Rates | | | | | | | | | | | | | | | | | | | |
| 21 | Delivery [(8)] | 136,196 | 20,675 | 12,474 | 18,043 | 5,144 | 192,531 | 164,862 | 19,246 | 18,330 | 16,337 | 6,701 | 225,475 | 28,666 | (1,429) | 5,856 | (1,706) | 1,557 | 32,945 | 17% |
| 22 | Storage and Transmission | 51,577 | 18,492 | 6,003 | 755 | 941 | 77,768 | 71,774 | 23,299 | 6,931 | (12) | 2,117 | 104,109 | 20,196 | 4,807 | 928 | (766) | 1,176 | 26,341 | 34% |
| 23 | Other Cost of Gas | 158,686 | 42,719 | 7,942 | 1,768 | 12,950 | 224,065 | 87,723 | 21,300 | 2,743 | 131 | 6,026 | 117,922 | (70,963) | (21,420) | (5,200) | (1,636) | (6,924) | (106,143) | (47%) |
| 24 | Total Revenue Requirement | 346,459 | 81,886 | 26,419 | 20,565 | 19,035 | 494,364 | 324,358 | 63,844 | 28,003 | 16,457 | 14,844 | 447,506 | (22,101) | (18,042) | 1,584 | (4,108) | (4,191) | (46,857) | (9%) |

Notes:
(1) Description of the local storage plant cost increase is provided at J.H-1-1-2, page 3.
(2) Other rate base includes net plant excluding local storage plant (line 1), working capital, and accumulated deferred taxes.
(3) Description of the Union North depreciation expense increase is provided at J.H-1-1-2, page 3.
(4) Cost of Gas costs include compressor fuel.
(5) Description of the Union North Distribution O&M cost increase is provided at J.H-1-1-2, page 3.
(6) Description of the cost allocation correction for sales and promotion O&M is provided at J.H-1-1-2, page 3.
(7) Description of the general operating and engineering O&M cost allocation update is provided at J.H-1-1-2, page 4.
(8) 2007 delivery-related revenue requirement excludes Rate 77.

Union North
Forecast Number of Customers, Contracted Demands, and Annual Volumes by Rate Class

| Line No. | Particulars ($000's) | R01 | R10 | R20 | R100 | R25 | R77 | Total |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) = sum (a to f) |
| | Number of Customers | | | | | | | |
| 1 | 2013 Proposed | 319,406 | 2,048 | 62 | 19 | 70 | - | 321,605 |
| 2 | 2011 Board-approved | 295,672 | 2,962 | 64 | 19 | 79 | 1 | 298,797 |
| 3 | 2007 Board-approved | 295,672 | 2,962 | 64 | 19 | 79 | 1 | 298,797 |
| 4 | Difference (line 1 - line 3) | 23,734 | (914) | (2) | - | (9) | (1) | 22,809 |
| | Contracted Demands ($10^3m^3/d$) | | | | | | | |
| 5 | 2013 Filed | - | - | 3,580 | 5,998 | - | - | 9,578 |
| 6 | 2011 Board-approved | - | - | 2,423 | 7,782 | - | - | 10,205 |
| 7 | 2007 Board-approved | - | - | 2,423 | 7,782 | - | - | 10,205 |
| 8 | Difference (line 5 - line 7) | - | - | 1,157 | (1,784) | - | - | (627) |
| | Annual Volumes ($10^3m^3$) | | | | | | | |
| 9 | 2013 Filed | 855,598 | 316,269 | 628,164 | 1,895,488 | 129,481 | - | 3,825,000 |
| 10 | 2011 Board-approved | 870,427 | 422,932 | 526,116 | 2,254,074 | 104,645 | - | 4,178,194 |
| 11 | 2007 Board-approved | 905,311 | 381,370 | 525,588 | 2,275,112 | 104,645 | - | 4,192,026 |
| 12 | Difference - 2013 vs. 2011 (line 9 - line 10) | (14,829) | (106,663) | 102,048 | (358,586) | 24,836 | - | (353,194) |
| 13 | Difference - 2013 vs. 2007 (line 9 - line 11) | (49,713) | (65,101) | 102,576 | (379,624) | 24,836 | - | (367,026) |

Union North
DSM Amounts by Rate Class

| Line No. | Particulars ($000's) | R01 | R10 | R20 | R100 | R25 | R77 | Total |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) = sum (a to f) |
| | DSM Amounts in Rates | | | | | | | |
| 1 | 2013 Proposed | 3,755 | 1,194 | 981 | 1,809 | - | - | 7,739 |
| 2 | 2011 Board-approved | 2,380 | 2,053 | 1,477 | 2,375 | - | - | 8,285 |
| 3 | 2007 Board-approved | 1,626 | 1,402 | 1,009 | 1,622 | - | - | 5,659 |
| 4 | Difference - 2013 vs. 2011 (line 1 - line 2) | 1,375 | (859) | (496) | (566) | - | - | (546) |
| 5 | Difference - 2013 vs. 2007 (line 1 - line 3) | 2,129 | (208) | (28) | 187 | - | - | 2,080 |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Ref: J.E-2-15-4

Please explain how Union is responding to the declining revenues and volumes in the North delivery area.

---

Union looks to increase revenues and volumes in both Union South and Union North by expanding gas services through customer conversions, attracting new communities (e.g. Red Lake) and new customers (e.g. OPG Thunder Bay). Union also works with existing customers to encourage the use of natural gas through the installation of efficient natural gas technologies.

Also, as indicated at Exhibit J.H-1-1-2, there are a number of factors contributing to rates increases in the North. The costs allocated to Union North rate classes are reflective of the costs to provide service to the North. Union has responded to the increases and allocated costs as part of the rate design process by allocating approximately 50% of the transactional margins available for rate making to the North. This compares with 2007 Board-approved North rates which included an allocation of 36% of the available transactional margins.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Ref: J.E-2-15-4

Please provide a table showing the revenue-to-cost ratios before and after.

---

In Exhibit J.H-1-5-2, Union incorrectly stated that the revenue-to-cost ratio for all in-franchise rate classes, after including proposed 2013 S&T transactional margin, is 95.3%. The correct revenue-to-cost ratio is 97.6%, as shown at Exhibit H3, Tab 1, Schedule 1, page 2, line 8, column (h).

If Union were to exclude the proposed 2013 S&T transactional margin of $20.852 million, the resulting revenue-to-cost ratio for all in-franchise rate classes would be 1.0%.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Please calculate the same numbers conceptually for a 5,000 breakpoint that is 49,999 to 50,001, again for all three years.

---

Please see the Attachment.

Annual Delivery Bill
before and after 2014 General Service Volume Breakpoint Change

| | | Annual Delivery Bill ($) | | | Percentage Change | |
|---|---|---|---|---|---|---|
| Line No. | Particulars | 2011 Approved (a) | 2013 Proposed (b) | 2014 Proposed (c) | 2013 Proposed Increase from Current Approved (d)= (b/a) | 2014 Proposed Redesign (e)=(c/b) |
| | General Service customer at: | | | | | |
| | Union North | | | | | |
| 1 | Annual Volume of 49,999 $m^3$ | 3,432.95 | 4,646.80 | 3,830.85 | 35.4% | -17.6% |
| 2 | Annual Volume of 50,001 $m^3$ | 3,688.04 | 4,097.03 | 3,830.98 | 11.1% | -6.5% |
| | Union South | | | | | |
| 3 | Annual Volume of 49,999 $m^3$ | 1,791.80 | 2,095.43 | 2,143.80 | 16.9% | 2.3% |
| 4 | Annual Volume of 50,001 $m^3$ | 2,613.71 | 2,915.16 | 2,143.87 | 11.5% | -26.5% |
| | General Service customer at: | | | | | |
| | Union North | | | | | |
| 5 | Annual Volume of 4,999 $m^3$ | 595.69 | 727.86 | 726.32 | 22.2% | -0.2% |
| 6 | Annual Volume of 5,001 $m^3$ | 595.83 | 728.04 | 771.66 | 22.2% | 6.0% |
| | Union South | | | | | |
| 7 | Annual Volume of 4,999 $m^3$ | 407.93 | 449.09 | 451.30 | 10.1% | 0.5% |
| 8 | Annual Volume of 5,001 $m^3$ | 408.00 | 449.17 | 597.10 | 10.1% | 32.9% |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Pankrac

SEC TCQ 31. [J.H-3-15-3] Please provide responses to the questions asked.

---

a) Not confirmed. Based on Union's 2014 proposed annual volume breakpoint of 5,000 $m^3$, a customer in Rate M1 cannot consume 6,000 $m^3$ in any month.

Please see J.H-1-15-2 'Comparison of 2013 and 2014' and Attachment 3 for the comparison of the annual average rate for Rate M1 versus Rate M2 and Rate 01 versus Rate 10. The annual average rate for Rate M2 and Rate 10 is higher than the annual average rate for Rate M1 and Rate 01 respectively at the 5,000 $m^3$ breakpoint primarily as a result of Union's proposal to set the Rate M2 and Rate 10 monthly customer charge at $35.

Union arrived at the proposed 2014 monthly customer charge of $35 for Rate 10 and Rate M2 by taking the approximate mid-point of the monthly customer charges required to recover all customer-related costs.

Union has set the Rate M2 and Rate 10 monthly customer charge at $35 to achieve a reasonable recovery of fixed costs. As shown at J.H-1-15-2 Attachment 4, Line 2, columns b) plus d), the proposed monthly customer charge is designed to recover $34.498 million in fixed costs. The remaining fixed costs of $85.721 million, shown at Line 7, columns b plus d, are recovered in volumetric rates.

b) Confirmed, customers shifting from Rate M1 to Rate M2 in 2014 will see bill increases. Please see J.H-1-14-2 Attachment 1 attached.

c) There are no diseconomies of scale affecting the cost to distribute to higher volume general service customers. Please see J.H-1-15-2 'Cost Differences between Small Volume and Large Volume General Service rate classes' and part a) above.

d) Union's March 27, 2012 updated filing shows an increase in the Rate M1 delivery rate and a decrease in the Rate M2 delivery rate for 2014 compared to Union's November 23, 2011 filing.

The delivery rate changes are the result of the increase in Union's revenue deficiency in the March 27, 2012 filing and updates to the allocation of S&T transactional margin to rate classes. The updates to S&T transactional margin were required to manage rate continuity.

Accordingly, Rate M1 delivery rates have increased while Rate M2 delivery rates for 2014 have decreased from Union's November 23, 2011 filing.

e) Please see J.H-1-15-2 Attachments 1 and 3 and part a) above.

f) Please see J.H-1-15-2 Attachment 3. At an annual volume breakpoint of 5,000 $m^3$, the annual average rate for Rate 10 is higher than the annual average rate for Rate 01. Please also see part a) above.

Annual General Service Delivery Bill Impacts - Union South
of Proposed 2014 Change in Annual Volume Breakpoint (1)

| Annual | 2013 Proposed with Annual Volume Breakpoint of 50,000 $m^3$ | | 2014 Proposed with Annual Volume Breakpoint of 5,000 $m^3$ | | Bill Impacts | |
|---|---|---|---|---|---|---|
| Volume | Rate M1 | Rate M2 | Rate M1 | Rate M2 | $ | % |
| 1,800 | 327.69 | | 328.98 | | 1.29 | 0.4% |
| 2,200 | 343.16 | | 344.58 | | 1.42 | 0.4% |
| 2,600 | 358.55 | | 360.08 | | 1.53 | 0.4% |
| 3,000 | 373.82 | | 375.47 | | 1.65 | 0.4% |
| 5,000 | 449.13 | | 451.34 | | 2.21 | 0.5% |
| 5,001 | 449.17 | | | 597.10 | 147.93 | 32.9% |
| 6,000 | 486.16 | | | 632.34 | 146.18 | 30.1% |
| 7,000 | 523.15 | | | 667.37 | 144.22 | 27.6% |
| 10,000 | 633.91 | | | 771.65 | 137.74 | 21.7% |
| 20,000 | 999.67 | | | 1,117.24 | 117.58 | 11.8% |
| 30,000 | 1,364.94 | | | 1,461.55 | 96.62 | 7.1% |
| 50,000 | 2,095.47 | | | 2,143.84 | 48.37 | 2.3% |
| 60,000 | | 3,316.76 | | 2,478.58 | (838.18) | -25.3% |
| 70,000 | | 3,717.42 | | 2,812.62 | (904.79) | -24.3% |
| 80,000 | | 4,117.07 | | 3,146.02 | (971.06) | -23.6% |
| 100,000 | | 4,911.88 | | 3,809.88 | (1,102.00) | -22.4% |
| 200,000 | | 8,736.83 | | 7,084.44 | (1,652.39) | -18.9% |
| 300,000 | | 12,470.81 | | 10,332.91 | (2,137.89) | -17.1% |
| 500,000 | | 19,846.07 | | 16,797.86 | (3,048.22) | -15.4% |

Notes:
(1) Grey shading represents all changes when compared to Exhibit H1, Tab 1, Updated, Table 12, page 27.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Pankrac

SEC TCQ 33. [J.H-4-4-1] Please extend Table 1 to include 2014 proposed $ and %.

---------------------------------------------------------------------------------------------------------

Please see the Attachment.

## Attachment 1

### Percentage of 2013 & 2014 Proposed Customer-related Costs recovered by 2013 & 2014 Proposed Monthly Customer Charges

| Line No. | Rate Class | 2013 Proposed Customer-related Costs ($000's) | 2013 Proposed Monthly Customer Charge Revenue ($000's) | Percent Recovery | 2014 Proposed Customer-related Costs ($000's) | 2014 Proposed Monthly Customer Charge Revenue ($000's) | Percent Recovery |
|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) = (b / a) | (d) | (e) | (f) = (e / d) |
| 1 | Rate 01 | 117,795 | 80,490 | 68.3% | 111,038 | 75,654 | 68.1% |
| 2 | Rate 10 | 3,770 | 1,720 | 45.6% | 10,527 | 8,921 | 84.7% |
| 3 | Rate M1 | 282,101 | 266,843 | 94.6% | 269,087 | 253,207 | 94.1% |
| 4 | Rate M2 | 8,992 | 5,702 | 63.4% | 22,006 | 25,577 | 116.2% |
| 5 | Total | 412,658 | 354,755 | 86.0% | 412,658 | 363,359 | 88.1% |

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Please provide the costs allocated to M1, M2, 01, and 010 for 2013 and 2014; and what adjustments were made to get from one to the other.

---

Please see the Attachment for the re-allocation of 2014 general service delivery-related costs. The methodology used to re-allocate delivery-related costs between Rate 01 and Rate 10 and Rate M1 and Rate M2 is consistent with the methodology approved by the Board in 2007 to split the Rate M2 rate class into Rate M1 and Rate M2.

The Attachment, page 1 summarizes the general service delivery-related costs in 2013 and 2014. As shown at lines 3 and 6, columns (c) and (f), total general service delivery-related costs remain unchanged in 2013 and 2014 by operating area.

The Attachment, page 2 summarizes the re-allocation of customer-related costs for Rate 01 and Rate 10 and Rate M1 and Rate M2 based on the proposed 2014 annual volume breakpoint of 5,000 $m^3$.

Customer-related costs are re-allocated between Rate 01 and Rate 10 and Rate M1 and Rate M2 using a weighted number of customers based on 2010 actual customers identified at Exhibit H1, Tab 1, Updated, Tables 5 and 6. The weighted number of customers is derived by applying weights to the actual customer counts to ensure a proper allocation of costs. The weights used are 1.0 for residential, 1.5 for commercial and 2.0 for industrial. Based on the weighted number of customers by rate class, the customer-related costs are allocated between Rate 01 and Rate 10 and Rate M1 and Rate M2 as shown at lines 1 to 18.

The Attachment, page 3 summarizes the re-allocation of the remaining delivery-related costs for Rate 01 and Rate 10 and Rate M1 and Rate M2. The remaining delivery-related costs are re-allocated between rate classes by operating area based on 2010 actual volumes and the 5,000 $m^3$ annual volume breakpoint. The allocation of the remaining delivery-related costs is shown at lines 1 to 6.

2013 and 2014 Delivery-related Costs
for Rate 01, Rate 10, Rate M1 and Rate M2

| Line No. | Particulars ($000's) | Proposed 2013 General Service Revenue Requirement with Annual Volume breakpoint at 50,000 $m^3$ Customer-Related | | Other Delivery | Total | Proposed 2014 General Service Revenue Requirement with Annual Volume breakpoint at 5,000 $m^3$ Customer-Related | Other Delivery | Total |
|---|---|---|---|---|---|---|---|---|
| | | (a) | | (b) | (c) | (d) | (e) | (f) |
| | Union North | | | | | | | |
| 1 | Rate 01 | 117,795 | (1) | 47,066 | 164,861 | 111,039 | 35,211 | 146,250 |
| 2 | Rate 10 | 3,770 | (2) | 15,476 | 19,246 | 10,527 | 27,330 | 37,857 |
| 3 | Total- Union North | 121,565 | | 62,542 | 184,107 | 121,566 | 62,542 | 184,107 |
| | Union South | | | | | | | |
| 4 | Rate M1 | 282,101 | (3) | 99,137 | 381,238 | 269,086 | 75,911 | 344,998 |
| 5 | Rate M2 | 8,992 | (4) | 36,461 | 45,453 | 22,006 | 59,687 | 81,693 |
| 6 | Total - Union South | 291,093 | | 135,598 | 426,691 | 291,093 | 135,598 | 426,691 |

Notes:
(1) Exhibit H3, Tab 1, Schedule 2, page 1, line 1, column (e).
(2) Exhibit H3, Tab 1, Schedule 2, page 2, line 1, column (e).
(3) Exhibit H3, Tab 1, Schedule 2, page 5, line 1, column (e).
(4) Exhibit H3, Tab 1, Schedule 2, page 5, line 11, column (e).

2014 Allocation of Customer-related Costs
for Rate 01, Rate 10, Rate M1 and Rate M2
based on an annual volume breakpoint of 5,000 $m^3$

| Line No. | Particulars | 2010 Actual Number of Customers at 50,000 $m^3$ breakpoint | 2010 Actual Number of Customers at 5,000 $m^3$ breakpoint | Weighting | Weighted Number of Customers | Percentage | Customer-Related Costs ($000's) | General Service Allocated Costs Attachment Reference |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d)= (b) * (c) | (e) based on (d) | (f) | (g) |
| | Union North | | | | | | | |
| | Rate 01 | | | | | | | |
| 1 | Residential | 272,963 | 267,742 | 1.0 | 267,742 | | | |
| 2 | Commercial | 26,413 | 13,498 | 1.5 | 20,247 | | | |
| 3 | Industrial | 33 | 6 | 2.0 | 12 | | | |
| 4 | Total | 299,409 (1) | 281,246 (3) | | 288,001 | 91.3% | 111,039 (9) | |
| | Rate 10 | | | | | | | |
| 5 | Residential | 4 | 5,225 | 1.0 | 5,225 | | | |
| 6 | Commercial | 1,619 | 14,534 | 1.5 | 21,801 | | | |
| 7 | Industrial | 112 | 139 | 2.0 | 278 | | | |
| 8 | Total | 1,735 (2) | 19,898 (4) | | 27,304 | 8.7% | 10,527 (10) | |
| 9 | Total - Union North | 301,144 | 301,144 | | 315,305 | 100.0% | 121,565 | Page 1, line 3, column(a) |
| | Union South | | | | | | | |
| | Rate M1 | | | | | | | |
| 10 | Residential | 915,184 | 898,064 | 1.0 | 898,064 | | | |
| 11 | Commercial | 73,418 | 42,241 | 1.5 | 63,362 | | | |
| 12 | Industrial | 3,982 | 1,432 | 2.0 | 2,864 | | | |
| 13 | Total | 992,584 (5) | 941,737 (7) | | 964,290 | 92.4% | 269,086 (11) | |
| | Rate M2 | | | | | | | |
| 14 | Residential | 41 | 17,161 | 1.0 | 17,161 | | | |
| 15 | Commercial | 5,078 | 36,255 | 1.5 | 54,383 | | | |
| 16 | Industrial | 1,109 | 3,659 | 2.0 | 7,318 | | | |
| 17 | Total | 6,228 (6) | 57,075 (8) | | 78,862 | 7.6% | 22,006 (12) | |
| 18 | Total - Union South | 998,812 | 998,812 | | 1,043,151 | 100.0% | 291,093 | Page 1, line 6, column (a) |

Notes:
(1) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (b).
(2) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (e).
(3) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (b).
(4) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (e).
(5) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (b).
(6) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (e).
(7) Exhibit H1, Tab 1, Page 16, Table 5. Rate M1 customers in column (b) above per Table 5, lines 5-8, column (b).
(8) Exhibit H1, Tab 1, Page 16, Table 5. Rate M2 customers in column (b) above per Table 5, lines 5-8, column (e).
(9) Rate 01 Customer-Related costs at the 5,000 $m^3$ annual volume breakpoint: 91.3% * 121,565 = $111,039.
(10) Rate 10 Customer-Related costs at the 5,000 $m^3$ annual volume breakpoint: 8.7% * 121,565 = $10,527.
(11) Rate M1 Customer-Related costs at the 5,000 $m^3$ annual volume breakpoint: 92.4% * 291,093 = $269,086.
(12) Rate M2 Customer-Related costs at the 5,000 $m^3$ annual volume breakpoint: 7.6% * 291,093 = $22,006.

2014 Allocation of Other Delivery-related Costs
for Rate 01, Rate 10, Rate M1 amd Rate M2
based on an annual volume breakpoint fo 5,000 $m^3$

| Line No. | Particulars | 2010 Actual Annual Volume ($m^3$) at 50,000 $m^3$ breakpoint | | 2010 Actual Annual Volume ($m^3$) at 5,000 $m^3$ breakpoint | | Percentage | Other Delivery Costs ($000's) | | General Service Allocated Costs Attachment Reference |
|---|---|---|---|---|---|---|---|---|---|
| | | (a) | | (b) | | (c) based on (b) | (d) | | (e) |
| | Union North | | | | | | | | |
| 1 | Rate 01 | 837,395,960 | (1) | 609,371,320 | (3) | 56.3% | 35,212 | (9) | |
| 2 | Rate 10 | 244,955,407 | (2) | 472,980,046 | (4) | 43.7% | 27,330 | (10) | |
| 3 | Total - Union North | 1,082,351,367 | | 1,082,351,367 | | 100.0% | 62,542 | | Page 1, line 3, column (b) |
| | Union South | | | | | | | | |
| 4 | Rate M1 | 2,679,588,627 | (5) | 2,043,883,921 | (7) | 56.0% | 75,911 | (11) | |
| 5 | Rate M2 | 971,362,682 | (6) | 1,607,037,388 | (8) | 44.0% | 59,687 | (12) | |
| 6 | Total - Union South | 3,650,951,309 | | 3,650,921,309 | | 100.0% | 135,598 | | Page 1, line 6, column (b) |

Notes:
(1) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (a).
(2) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (d).
(3) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (a).
(4) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (d).
(5) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (a).
(6) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (d).
(7) Exhibit H1, Tab 1, Page 16, Table 5, lines 5-8, column (a).
(8) Exhibit H1, Tab 1, Page 16, Table 5, lines 5-8, column (d).
(9) Rate 01 Other Delivery-related costs at the 5,000 $m^3$ annual volume breakpoint: 56.3% * 62,542 = $35,212.
(10) Rate 10 Other Delivery-related costs at the 5,000 $m^3$ annual volume breakpoint: 43.7% * 62,542 = $27,330.
(11) Rate M1 Other Delivery-related costs at the 5,000 $m^3$ annual volume breakpoint: 56.0% *135,598 = $75,911.
(12) Rate M2 Other Delivery-related costs at the 5,000 $m^3$ annual volume breakpoint: 44.0% *135,598 = $59,687.