EB-2011-0210

Union Gas 2013 Rate Case

BOMA's Factum for Argument
August 2012

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1. Introduction

BOMA's argument will deal with all the major issues dealing with the revenue requirement and selected issues in cost allocation and rate design. On the revenue requirement, we will address:

- the capital structure
- the Parkway West component of Union's capital budget, especially its strategic significance
- the Storage and Transportation ("S&T") services revenue requirement with particular emphasis on the proper characterization of FT-RAM related revenues
- gas costs and the absence of a credible gas supply plan
- the revenue forecasts for the general service and contract customers.

Capital Structure

Union has proposed an increase in the equity portion of its capital structure from 36% to 40%, effective January 1. The increase would have the effect of increasing the test year revenue requirement by $17.3 million and is a one-time 11% increase in equity thickness. BOMA is opposed to Union's initiative for several reasons.

First, and most important, Union has failed to justify its proposal on the basis of the Board's stated policy on changes to debt to equity ratios for gas utilities, which is that a utility's equity thickness would be changed only where there was a clear, identifiable change to the utility's business risk and/or financial risk, from the time the existing ratio was set. The Board recently stated:

> "The Board's draft guidelines assume that the base capital structure will remain <u>relatively constant over time</u> and that a full reassessment of a gas utility capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk" (Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (the "Report" at p50) (emphasis added).

Year to year modifications to utilities' return on equity are meant to reflect changes in capital market conditions. The 36% thickness was set as part of a comprehensive Settlement Agreement, approved by the Board in EB-2005-0520.

Union's evidence is that there has been no change in Union's business risk since the EB-2005-0520 decision. It has admitted in effect that it does not meet the Board's criteria for changes to the percent of equity permitted in its capital structure. Union agreed that its overall business and financial risk has not changed materially since 2004 (V4, p128). Moreover, Union did not ask its experts in this case to analyze whether there have been any significant changes in Union's business and/or financial risks since 2007. They were not asked to do that (V4, p128).

BOMA would support Dr. Booth's view that Union's business/financial risk has not increased since it was last litigated, in 2004, and has probably slightly declined (V6, p6).

For example, Union has agreed that one business risk, gas cost risk, has declined with the collapse in gas prices in North America. It states at p17 of Ex. A2, T1, Sch 1, that:

> "Low energy prices have a positive impact on consumers and economic growth. Lower costs for consumers are expected to promote economic growth as consumer spending increases. Any consumer led business cycle improvement will positively impact the Ontario economy leading to higher housing starts, greater conversion from other fuels, and increased industrial output".

Union's evidence also states that:

> "Low energy costs also have a positive impact on Union's cash flows and operating costs. The impact includes but is not limited to: bad debt expense; gas used to heat Union's buildings; fuel gas used in compressor stations; financial charges in relation to the financing and carrying costs of lower-value natural gas inventory; and, the value of UFG".

Financial Risk

Dr. Booth notes in his testimony that the litmus test of whether the Board "has got it right" is whether the regulated utility can access capital on reasonable terms (Booth, p20). BOMA agrees with Dr. Booth's assessment that Union continues to have reasonable access to credit markets, evidenced by its planned debt issuance in the amount of $125 million at 3.9%. Dr. Booth noted that:

> "There is no question that even without the Board's allowed ROE forecast and an increase in common equity, Union's financial health is currently much better than it was in 2004".

In a recent decision on Natural Resource Gas Ltd. (NRG EB-2010-0018), the Board stated:

> "The Board has a cost of capital in place that is applicable to all electric utilities, and NRG's size and profile is similar to a number of electric utilities as opposed to the two large gas utilities (Enbridge and Union)".

The Board's view may be contracted with that of Mr. Fetter, Union's witness, who used the Board's recent NRG decision as a precedent for allowing Union Gas the same equity thickness. He stated:

> "In addition, a review of Canadian rate decisions since the time of the Concentric Report also shows a positive movement in authorized equity thickness. For example, the OEB

> set a 40% equity thickness for Natural Resource Gas in 2010, stating that '(NRG has presented no evidence that its risk profile is significantly different from other utilities in Ontario)'."

Based on the above interpretation alone, the Board should give little weight to Mr. Fetter's evidence.

More generally, with respect to financial risk, there is no evidence that from a cash flow or access to capital markets perspectives, Union requires additional equity. More particularly, Union's evidence is that:

- Union has maintained strong credit ratings over the last several years. DBRS has rated Union with an A rating, since 1997, the year in which it began to rate the utility, and S&P has given it a BBB+ rating, since 2003, the same rating as its parent, Spectra Energy (JE-2-12-8, p2) (S&P has a policy that it will not rate a utility higher than is parent unless the subsidiary is completely protected from financial and operating interference by the parent). (Booth, p2). The Undertakings from Union to the Ontario Government do provide substantial protection to Union from predatory behavior by its parent, particularly with respect to maintenance of appropriate utility equity, sale of assets, and diversification of the business away from gas distribution, transmission and storage. They do not deal with dividend policy and cash management policy.

- Union has maintained strong cash flow and cash positions; for example, Union has paid dividends to its parent company of $145 million in 2011, $190 million in 2010, and $165 million in 2009, a total of $500 million in three years (A3, T2, p5).

- Union has not had any difficulty selling debt to the market when it needed to do so over the last several years (JE-2-1-1, p1). Union's evidence in response to JE-2-12-8 shows that Union has frequently issued unsecured debt over the last 10 years at very competitive rates in relation to utility rates generally. As noted earlier, it plans to issue debt in 2013 at 3.9%. Utilities are a big part of the corporate debt market in Canada.

- Union has earned its weather normalized return aside from modest under-earning in 1991 and 1992, for every year since 1990, and on average, has over-earned by 1.22% since 1990 (Booth, p24) (JE-2-12-9(b)).

- During the most recent IRM period (2007 to 2012, inclusive) Union has over-earned in the amount of $288.7 million, of which only 21.2% was shared with ratepayers (JE-3-5-1; Booth, p25).

Interest Rate Coverage

Union's current interest coverage ratio is 2.74% which is well above the 2.0% minimum interest coverage ratio set out in Union's trust indenture (JE-2-12-9). That is an increase from 2.4% in 2010, 2.4% in 2009, 2.47% in 2008, and 2.24% in 2007. (DBRS Rating Report, January 31, 2011).

Interest Coverage Ratios

As an aside, Union has introduced, in response to cross-examination, the notion of an interest rate coverage of the regulated part of the corporation only, and noted that that "ratio", under certain circumstances, could slip below the mandated 2x ratio in the trust indenture (V6, p152). This notion is a red herring. Interest rate coverages are determined, and always have been determined at the corporate level, not the divisional level. The 2x threshold referred to in the trust indenture and the MTN prospectus is referred to as the EBIT interest coverage of Union Gas Limited. Union Gas Limited contains both an unregulated business and a regulated business (the utilities). They are divisions of the same company. The unregulated storage business is not in a separate company. The interest rate ratios set out in the corporate trust indenture, and are incorporated in the corporate covenants of the issuer of the securities, the bonds and notes, which is Union Gas Limited. The notion of a regulatory division interest coverage ratio has no relevance to the matter under discussion in this case. As to the point Union made that the unregulated part of the company is "subsidizing the regulated part" (V5, p64), I would note Union's response to Mr. Sommerville's question, that the larger the unregulated portion of Union's business becomes, the more risky the corporation becomes; a view incidentally shared by DBRS [A3, T6, p2 of full analysis]. That said, both DBRS and S&P made the point that, at this time, the unregulated storage business is too small to have a material impact on the risk profile of Union Gas Limited.

<u>Expense</u>

Given the relatively low current debt cost, of less than 4% versus a pre-tax equity cost of 12.7% (equivalent to the after-tax 9.58% requested return on equity) calculated at a 25% assumed tax rate, every dollar of debt shifted to equity costs the ratepayers 8.77%. This makes it particularly damaging to change the ratio at this time. As noted above, the pre-tax cost of the proposed change in capital structure makes up a significant part of Union's claimed revenue deficiency.

In a report on Union issued January 24, 2012, DBRS expects Union to maintain its EBIT interest coverage above 2.2x which is in line with the current rating (JE-2-15-3, Attachment 2).

<u>Summary of the FT-RAM Argument</u>

1. Revenue arising from transaction Union entered into with third parties which utilized FT-RAM credits should be treated, and should have been treated, as reduction to gas costs

because they were earned by Union, as a result of its holding LTFT service and related services on the TCPL Mainline. RAM credits are a feature of the TransCanada Tariff. They are embedded in TransCanada's Interruptible Toll Transportation ("IT") Toll Schedule, both of which were approved by the National Energy Board. The initial RAM pilot project in 2004 was approved by NEB, as were all subsequent modifications to RAM features. Union admits they are features of TransCanada FT service and the part of the TCPL tariff and the TCPL Toll Schedule. The stated purpose of FT-RAM feature was to induce shippers to use more, or decontract less, FT service, by offsetting some of the costs of holding that service.

2. Except for a very small percentage of its FT-RAM credits which Union used to offset Unabsorbed Demand Charges ("UDC") and TCPL LBA charges, Union used the credits to engage in a series of transactions with third parties (mostly marketers) to create incremental revenues which it labeled "exchange revenue" or "regulated revenue". It kept those revenues for its shareholder.

3. They treated the revenues, generated by the use of FT-RAM credits, the very same way they treated exchange revenues that they had historically generated by carrying out exchanges with third parties without the use of FT-RAM, except that prior to 2007 ratepayers shared in the revenues, both forecast and margins through a Transportation Exchanges Service Deferral Account, 179-69. After many attempts, Union closed that account in 2007 just before FT-RAM enabled revenues took off.

4. Union has admitted that their S&T "exchange business" was greatly enhanced by their use of FT-RAM credits.

Broadly speaking, Union did these transactions using FT-RAM credits in two general ways. They either kept the IT credits and used them to acquire low cost interruptible service to move the gas which they had contracted to transport via LTFT service, to an (often) upstream delivery area relative to the delivery area of the original FT contracts, and then used the "excess IT credits" to fund incremental transactions. Alternatively, they assigned the FT capacity to a third party, thereby creating an "empty pipe" and RAM credits for that third party which the third party would fill using IT service. In each case, the overall revenues from the transaction were shared between Union and the third parties. Union's share of this revenue was streamed to Union's shareholder, notwithstanding the transactions were underpinned by the LTFT capacity, paid for by ratepayers, and the FT-RAM credits were an attribute of that capacity.

5. The issue of whether the Transportation Exchange Services Account (179-69) deferral account into which "exchange revenue" margins were accounted for prior to 2007, but was then closed would have been irrelevant to this issue, had Union treated FT-RAM related revenue properly as reduction in gas costs. Since all of the revenue would have been paid through to ratepayers via the QRAM process, a deferral account would not have been necessary. However, given that Union treated FT-RAM related revenue as S&T revenues, the closure of the deferral account in 2007 meant that the ratepayers received none of the revenue in the years that saw largest use in FT-RAM related revenues, 2009 to 2012. As noted above, the transactional series deferral account was eliminated as part of a Settlement Agreement dated January 3, 2008 in EB-2007-0606 (p16), on the eve of a rapid expansion of RAM-related revenues.

6. Union's claim that these revenues should go to the shareholders, subject to whatever sharing with customers is required due to the earning sharing provision of the current IRM regime is, accordingly, based on a mistaken characterization of these amounts. The amounts never were exchange revenues and should never have been treated as such. Moreover, BOMA sees no real difference between test year RAM related revenues and any RAM related revenues accrued since 2004 that have not yet been credited to ratepayers, other than the procedures by which the funds can be returned to ratepayers. So Union's claim that under IRM, it had the right to maximize profits within the parameters of the formula does not hold up. If the revenues are properly characterized as gas reduction, they become a Y-factor (pass through) under IRM.

7. In our view, any RAM revenue, or "RAM replacement" revenues, arising out of the OEB's upcoming decision in RH-003-0211, accruing in the test year should be deemed by the Board to be gas costs and treated accordingly. BOMA will take the same position in the EB-2011-0087 case with respect to the 2011 RAM revenues, and in next year's equivalent case, for 2012 RAM related revenues. If the Board orders restitution in these cases, BOMA will also likely ask the Board to open a proceeding on its own motion to review the payment of RAM-related revenues to shareholders for the years 2008 through 2012. The Board initiated a similar motion in EB-2012-0206.

RAM Related Revenues – The Numbers

In the four years 2009, 2010, 2011, and 2012, Union Gas has earned $67.3 million in revenues from transactions with third parties, made possible by the use of FT-RAM credits obtained from

TransCanada Pipelines Ltd. (K7.3)[1]. In BOMA's view, Union has mischaracterized these revenues as S&T revenue and has wrongly appropriated them to its shareholders. For the test year, Union has forecast $11.6 million of FT-RAM generated revenues (JC-4-7-9), on the assumption that FT-RAM will continue essentially in its current form. The NEB is widely expected to issue its decision in that case in the first half of 2013. Union has stated that TCPL has estimated it would take until approximately May 2013 to make all changes it proposed in its RH-003-2011 evidence including the elimination of FT-RAM. BOMA's view is that, in the event the NEB decides that FT-RAM should be discontinued, it will be well into the Spring 2013 before FT-RAM ceases to be available, and existing transactions that extend into 2013 would likely be grandfathered.

In BOMA's view, 2013 revenues, net of costs incurred to generate them, should be and should have treated as reduction in gas costs and passed through to ratepayers through the QRAM mechanism during 2013.

It is a truism that Union's gas costs include both the commodity costs of system gas and the pipeline transportation costs that underpin the gas supply for both system gas and the gas used by bundled-T customers, which includes almost all T1 customers in the north, and virtually all direct purchase customers in Union South. Adjustments to rates are made quarterly to reflect changes to the gas commodity costs and upstream pipeline tolls, as required by the provisions of the Ontario Energy Board Act.

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[1] Given the latest estimate of 2012 FT-RAM related revenues by Union, the $67.3 million will increase to $85.2 million. [These numbers are all based on the numbers contained in JC.4-7-9, and reflected in K7.3].

<u>FT-RAM Related Revenues</u>

Resolution 04.2009 of the Tolls Task Force, dated January 7, 2009, entitled FT-RAM, STS-RAM, STS-L-RAM - Permanent Tariff Feature, states that RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada mainline and that the motivation behind RAM is to promote the renewal of incremental contracting for long-haul FT service (JP-1-16-2). The resolution was unanimously approved by the Tolls Task Force on January 7, 2009, and was sent to the National Energy Board, under cover of a letter from TransCanada on January 16, 2009 (JD-1-16-2). The NEB approved the amendments, effective November 1, 2009, shortly thereafter. The NEB had previously approved "pilot project" version of FT-RAM, a gradual expansion to its applicability in a series of orders and letters over the period 2004 to 2007 (JD-1-16-2, Attachment 1).

The FT-RAM tariff feature provides that holders of mainline Long-Haul Firm Transportation (LTFT) (defined as transportation contracts that originate in Alberta or Saskatchewan), Short-Haul FT, which is linked to a LTFT contract, and STS and STS-L (STS service for marketers) transportation services on the TransCanada mainline earn dollar credits for each unit of capacity held during any contract month or part thereof. The calculation of amount of the dollar credit earned is shown by the example provided by TCPL in its document entitled RAM (Risk Alleviation Mechanism) June 2010, p2. The dollar values of the credits are calculated daily based on the customer's daily Demand Charge. The shipper may use these dollar credits to purchase interruptible service ("IT service") on TransCanada during that month. They may be used on any TransCanada path, that is between any TCPL receipt and delivery point to transport gas between which IT service is offered, not just the path on which the shipper earned the credits. Since IT (and FT) tolls are less on the shorter paths, and most TCPL paths are shorter than the Empress/Parkway path or Empress to the Eastern Zone path, many units of IT transport can be purchased on these shorter paths, with one dollar of FT long-haul toll credits. There is substantial "leverage" in the RAM feature. The only precondition is that the credits must be used in the month in which they are earned. TransCanada's Interruptible Transportation Service, ("IT") Toll Schedule contains provisions that provide for the deduction of the RAM credits from the nominal IT toll in order to determine the actual IT toll paid by the shipper (TransCanada Pipelines Transportation Tariff, IT Toll Schedule, section 4, sheet #5). Application of the credits allow the IT service be purchased for the commodity component of the IT toll, which is very small.

The party that earns the credits, the holder of eligible TCPL capacity, in this case Union Gas, can use the credits itself to purchase IT services. Alternatively, it can assign the FT capacity along with the credits to a third party, say a marketer, for any period it wishes, from a few days to a year. The credits themselves are not transferable, but go with the TransCanada Capacity. The marketer can then acquire IT service on TCPL and to engage with Union in various types of revenue earning transactions. Union's volumes of capacity assignments, over the period winter 2007 to summer (May) 2012, the Union Delivery Areas for which the capacity was assigned, and the length of time for which the capacity was assigned, are set out at Ex J4.2, Attachment, and JC-4-7-10, Attachment 1. The terms of the assignments range from a month to a full year. Many are for the winter or summer seasons for which it assigns the capacity. The contracts between Union and third parties provide for a sharing of the revenues from the transactions. The details of these transactions have never been made public. Although the credits must be deployed in a month in which they are generated, they can be saved and then deployed within one or two days in that month.

History of FT-RAM

TransCanada testified before the NEB that it had accepted a proposal from the Tolls Task Force ("TTF") in 2004 to establish a pilot program because the Task Force was almost unanimous in requesting the new service, and the company was starting to come under pressure from its shippers to moderate imminent toll increases.

The original proposal for FT-RAM was made by Shell Energy North America (Canada) Inc., the largest natural gas marketer in North America. The FT-RAM was originally approved by the National Energy Board (the "NEB") in a letter dated July 15, 2004 as a feature of FT service for a one year period commencing November 1, 2004 per the TransCanada Tolls Task Force Resolution 02.2004 (the complete history is outlined in JD-1-16-2; some of it is repeated here for convenience).

The FT-RAM pilot was extended for a period of one year by the Board in a letter dated September 6, 2005, and for a further year by a letter dated April 21, 2006, in response to TCPL Tolls Task Force ("TTF") Resolutions 20.2005 and 05.2006, respectively.

The Board, on the recommendation of the TTF, made modifications to the FT-RAM to include "linked" short-haul contracts effective April 1, 2006.

In a letter dated March 2, 2007, the Board approved an additional two year extension of the FT-RAM pilot commencing November 1, 2007 per TTF resolution 03.2007, and extended the scope of the pilot to include Storage Transportation Service (STS-RAM) and Storage Transportation

Services Limited (STS-L-RAM), per TTF Resolution 02.2007; all of the above at the instigation of Shell

As noted above, the NEB approved amendments to the IT Toll Schedules early in 2009, per TTF Resolution 04.2009, effective November 1, 2009.

The above history shows that the FT-RAM has been in place continuously since November 1, 2004. At no time prior to the filing of its evidence in the current tolls case, did TCPL or any other party propose the elimination of the FT-RAM service.

<u>The Gaming of FT-RAM</u>

Union's evidence is that the value of assignments of capacity was largely due to the FT-RAM credits that were transferred to the marketer along with the TCPL capacity; that the FT-RAM credits enhanced the value of the capacity.

The evidence filed by TransCanada in the ongoing RH-003-2011 proceeding before the National Energy Board [Part C, Business and Services Restructuring Proposal, Section 8.0 Mainline Service and Pricing Proposals, p26, Table 8.3] makes it clear that over ninety percent (90%) of the FT-RAM credits earned have not been exercised by the shippers that hold (mainly) Long Term Firm Transportation capacity on TransCanada and who earned the credits. Rather, they have been exercised by third parties, mainly gas marketers, to whom the LDCs shippers, including Union, have assigned FT capacity, notwithstanding the fact that they required it to transport gas to their franchise area. Union has referred to this activity on assigning capacity "when the line is full", as distinguished from assigning capacity which is currently not being utilized, which was the original intent of the program.

The same evidence also shows (p25 of 39, Figure 8.4) that the exercise of the credits has resulted in very large revenue reduction to the revenue which would otherwise have been payable to TransCanada as IT revenue, due to the exercise of the FT-RAM credits (which revenue would have had the effect of reducing FT tolls). The amount of potential IT revenue offset by RAM credits has increased from about $50 million in 2004 to $400 million in the first half of 2011 alone, or a total value of about $2 billion over the period 2004 to mid-2011; and considerably more since then. This gaming of the system by marketers and LDCs has produced the opposite result that TransCanada intended; it has resulted in a cannibalization of potential FT revenue by essentially free IT service. For example, over 90% of the gross potential IT service revenue in 2010 was offset by RAM credits [Figure 8.4]. Despite FT-RAM, Long-Haul FT Contracts or TransCanada have declined dramatically from 2005 to 2011 (Ibid. p24, Table 8.3).

As noted above, the National Energy Board amended TransCanada's IT toll structure in 2009 to build the FT-RAM reduction directly into the calculation of the toll, and had gradually, over the period 2004 to 2009, on the recommendation of the Tolls Task Force, increased the number of TCPL's transportation services that generated RAM credits through their Tariff Features (see JD-1-16-2). The incentive is very substantial, in that holders of FT service are able to purchase IT service for little more than the commodity portion (5%) of the IT toll on any path. The IT toll on TransCanada before application of the FT-RAM credit currently has a floor of 110% of the long term firm service toll for the path.

As noted above, the original purpose of the FT-RAM, as illustrated by its title of the service, Risk Alleviation Mechanism, was to induce long-haul firm transportation service shippers to continue to hold some FT service, and to reduce the overall cost of maintaining that long-haul service. TCPL thereby hoped to stem the relentless decontracting of long-haul capacity that had taken hold on its system, in about 2006. Parties seem to envisage that shippers would increase the amount of IT contracted for, but nonetheless would retain more LTFT than they would have otherwise; a balanced plan for tolls and shippers.

TransCanada states in its evidence in RH-003-2011 that its FT Tolls would decrease if the FT-RAM is eliminated. It alleges that the large amounts of virtually free IT service funded by RAM have cannibalized its FT service. Assuming only a $50 million increase in discretionary (IT) revenue. TCPL states that Empress SWDA (Dawn) toll would decline by 6¢/GJ (Ibid p29). BOMA considers an increase in IT revenue of $50 million from the elimination of RAM likely to be a conservative estimate given that IT revenues offset by RAM credits exceeded $400 million in 2011. Revenues of $150 million in new IT revenues would decrease Empress/Dawn tolls by 18¢/GJ (Ibid, p32).

As noted above, Union's shareholder has earned substantial revenue from the FT-RAM feature of the TCPL tolls, but it has earned those revenues not by purchasing IT service to benefit its ratepayers [with the exception of very modest amount to mitigate its UDC and LBA charges].

Had Union and other LDC shippers used the FT-RAM credits it earned to replace some of its FT service with IT service (at least for a part of each year), as opposed to using it directly or indirectly to generate exchange revenue, it would likely have substantially reduced its total TransCanada tolls, since the IT tolls after application of the credit could be less than 5% of the LTFT tolls for the same path. These would be accounted for under the OEB's system as reduction in gas transportation costs, which would have been credited to ratepayers through the quarterly QRAM procedure.

Instead, Union's S&T department commandeered these credits as a method of "supercharging the value" of the TCPL capacity Union held, and entered into a variety of transactions with marketers, in which Union assigned the TCPL capacity and the associated FT-RAM credits to the marketer, in return for substantial compensation, and often a contractual commitment from the marketer that Union's gas would arrive at delivery point designated by Union in the contract, which may or may not have been the original in Union's FT contract delivery point. Union needed to get the gas (which was orphaned when the original LTFT capacity which was to have transported it to the Union franchise area was assigned away to the marketer) to its original delivery point or some alternative. The compensation agreed to between the marketer and Union reflected a sharing of the net revenues the marketer was able to earn from the utilization of the FT-RAM credits, even after the cost to move the gas or have it moved, or exchanged for gas at Union's original stipulated alternate delivery point. Alternatively, Union would use the FT-RAM credits itself to purchase IT service directly to move the "stranded commodity" from its receipt point to the stated delivery point in the Union franchise area, and assign the capacity without the FT-RAM to the marketer. These expenditures were then accounted for as a "cost of the exchange transaction", rather than as a cost of generating revenues to reduce Union's gas costs. The best explanation of the two types of transactions which demonstrate how the LDCs' and marketers' net revenues are generated from RAM credits can be found are referred to in J7.3 and J7.6 (Undertakings of Mr. Isherwood to Mr. Quinn and Mr. Brett, respectively. These two types of transactions are referred to as capacity assignments and RAM Optimization, respectively in Attachment 2 of JC-4-7-9, which, when added together, are the basis for the RAM revenues shown in K7.3 (our emphasis).

FT-RAM Revenues and Gas Cost Reductions

In Union's pre-filed evidence under the heading "Changes in the Transportation Market", Union stated:

> "There has been a significant reduction in the load factors on TCPL long-haul service, resulting in increases in TCPL tolls. In order to mitigate this trend, TransCanada introduced the Firm Transportation Risk Alleviation Mechanism ("FT-RAM") program. This program gives firm shippers of long-haul, STS, or short-haul capacity linked to long-haul capacity, credits for any capacity left unutilized. These credits can then be spent, in the same month in which they received, on any interruptible service on TCPL's system. The program was designed to encourage shippers to remain contracted on TCPL's system" (Ex C1, T3, p11) (our emphasis).

Union described exchange revenues later in its pre-filed evidence to include net revenues generated from pipe releases or revenue from TCPL's FT-RAM program (C1, T3, p11).

In Table 4, entitled "Exchange Revenue", it set the actual and forecast exchange revenues for the years 2006 through 2013.

Under the table, it added the following comment:

> "The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT-RAM program, starting in 2008. Union's 2011 actual [exchange] revenue is primarily supported by TCPL's RAM program…" (C1, T3, p12).

Union also stated in its pre-filed evidence as updated on 2012-03-27, in commenting on TCPL's mainline tolls application, before the National Energy Board, that it supports TCPL's proposed changes:

> "at this time, Union generally supports these service and pricing changes intended to increase mainline revenue from transactional services and help preserve lower long-haul and short-haul rates for firm transport service, including the elimination of the FT-RAM. Union notes, however, that the elimination of TCPL's FT-RAM severely limits Union's ability to sell exchanges and other upstream transportation services. As indicated above, more of the major contributors to earnings sharing over the IRM term was Union's ability to successfully "optimize" its upstream capacity" (our emphasis) (A2, T1, Sch 1, p15).

Notwithstanding this statement, in its intervention in the RH-003-2011 proceeding, Union, along with its sister utilities, Enbridge and Gaz Metro, as members of the MAS group, has opposed the elimination of FT-RAM.

In its pre-filed evidence, entitled MAS Evidence, filed on March 9, 2012 in that proceeding, the MAS shippers stated that:

> "MAS believes that RAM provides a unique tool for mainline long-haul FT shippers to mitigate their risk of unutilized demand charges and differentiates TCPL from other pipelines. The continued and escalating use of RAM credits as provided in Table 8-5 (of TCPL's evidence) Contracting Behavior of 2010 Top Five RAM Users of the Application, demonstrates the market's use and reliance on RAM as a value-added FT service attribute".

In the current NEB tolls case, TransCanada has proposed that the FT-RAM be terminated on December 31st of this year. However, as noted earlier, Union, as part of a coalition of earlier Canada distributions, has objected to the discontinuance of FT-RAM, and would like it to continue indefinitely. As the hearing is ongoing, we do not know if FT-RAM will be continued, for how long, or in what form, and if it is discontinued, how long that "discontinuance process" will take, in other words, will FT-RAM be available for part of 2013. Some participants in the NEB proceedings predict that FT-RAM, in its current form, is not likely to be maintained, but that it may be superseded by a modified version of FT-RAM, with a new name and "mission" and somewhat more modest in scope. Union's evidence in this proceeding that the FT-RAM, even if it eventually eliminated, may carry on for part of the test year 2013, perhaps until May or June.

The amount of the net revenue received and the profitability of the transaction (the net revenue) is shown in table [K7.3]. BOMA believes that the revenues shown in Exhibit K7.3, which Union allocated to itself, should have been flowed through to shareholders, as gas costs reduction. Gas costs are a Y-factor [pass through item] under the current 5 year IRM plan, and so the reduction would have accrued to ratepayers. Had Union used the credits to purchase IT service to move some of its own gas to its customers, in lieu of the more expensive FT capacity, and gradually reduced its capacity for FT, the savings in total tolls for the "free IT" would, as noted above, have been treated as a reduction in gas costs. Why should the consequence be any different because the gas was moved by IT either by Union or by a third party as part of a transaction which included the assignment by Union of its FT capacity and attached FT-RAM credit to a third party, which used them to create value, which value then shared with Union's shareholder. The fact that Union characterizes the transaction as an "exchange" does not change the fact that the revenue obtained by Union for the transaction, net of its direct costs, if any, to get the gas it purchased at Empress to its customer should be considered a reduction in TCPL tolls, just as in the case where Union had directly replaced some of its FT service with IT service at a nominal price due to the dollar credit against the normal IT toll, and moved the gas to another delivery area. In that case, the misuse of the credit by converting the savings in transportation costs by using IT to an exchange "revenue" because some of the accrued IT credits were assigned to a third party for compensation in the form of a share in future revenue stream is perhaps most obvious.

The reduction should be treated in the same way as other pipelines toll charges, increases or decreases, that occur in the middle of a Union rate year, by an adjustment to gas costs through QRAM.

The issue is especially cogent now given the relentless and substantial increases in TCPL FT tolls that Union ratepayers have absorbed over the last few years. For example, TransCanada tolls from Empress to the Eastern Delivery Area (at 100% Load Factor) have increased from

$1.03 GJ in November 2007 to $2.24 GJ in May 2012, an increase of more than 100%. All this increase has been passed through to Union's ratepayers. Why are reductions not also passed through?

Gas costs are, of course, outside the IRM (they are a Y factor) and the fact that these transactions occurred during an IRM period, is not relevant to proper characterization of these amounts. They remain gas costs.

A further concern with Union's conduct is the potential negative impacts to ratepayers for the departure from the original gas plan, and the potential compromise to the integrity of the gas plan. If Union were able to direct third parties to deliver, or itself use FT-RAM credits to purchase IT to deliver gas to points in the northwestern, northern, and northeastern delivery areas during the winter, or to Dawn during the summer when the Union original capacity was to the Eastern or Central Delivery areas as they testified, why did it not contract capacity to the upstream delivery areas in the first instance, rather than burden ratepayers with the higher demand charges to the more distant eastern and central zones, so as to allow it the flexibility to earn more profits for the shareholder?

This issue is made more cogent by answers Union provided to concerns raised by me and Ms. Taylor, Mr. Quinn and others with respect to the absence of written gas supply plan, and a reluctance to take into account the interests of ratepayers in other delivery areas when making decisions on gas supply or transportation for one delivery area. BOMA is of the view that Union's "gas supply plan" has never been articulated properly in its evidence, and does not appear to exist other than in 43,000 pages of code. This is a big mistake. BOMA suggests that partly as a result of the last of a firm plan, Union S&T department were apparently allowed to do whatever they needed to do, in the interests of increasing revenues to shareholder, despite gas supply planning principles, and without ever informing the managers primarily responsible and accountable for the plan, and, as noted by Board staff in its submission, all the while using transportation assets that the ratepayers have paid for.

One would have thought that Union, as a good steward of its franchise, would have embraced the opportunity to offer its sales and bundled-T customers, a reduction in gas transportation costs, rather than appropriating the benefit of the reduced tolls to its shareholders. Union's behavior was outrageous; not in keeping with the conduct one expects from a utility with a monopoly franchise to serve the community.

Lack of Informed Consent

Union's senior management, Mr. Isherwood and Ms. Elliott testified that they did not know if at any time over the course of the IRM program, that Union had discussed in a proceeding with the Board or Board staff the proper characterization of FT-RAM enabled revenues. Ms. Elliott first answered, "Not that I am aware of" (V7, p84). An examination of the decisions and settlement conferences over the period of the IRM (2008 to 2012) does not show any discussion of the issues, of the proper characterization of the revenues it obtained from assigning its LTFT capacity away in order to "create" an unabsorbed demand charge liability for the marketer, and hence an opportunity for the marketer to obtain the RAM credits and use them to obtain virtually free IT service with which to implement various transactions that are revenue generating and share the revenues with the Union shareholder, was raised with the Board in any proceeding (V7, p84). Union certainly did not have any meaningful discussions with ratepayer's representatives over the status of such funds, nor did the Board give Union any informed consent to use the FT-RAM credits in the way it did.

BOMA urges the Board to determine that effective on the date of its decision in this case "revenues" obtained from selling FT-RAM credits be henceforth characterized as gas cost reduction, and that this characterization be maintained for any "modification" to the scope of the introduction of any similar mechanism by TCPL in 2013 and beyond.

Further, given the fact that Union in effect misappropriated the funds to the benefit of its shareholders from 2008 through 2012 to date, the Board should direct in both EB-2012-0087 and the equivalent case for 2012, be used to definitively determine the amounts of the funds that were characterized, and determine the best way for the funds to be returned to ratepayers, allowing for percentage of 10% share to remain with the shareholder as an incentive to be creative in the future. Union would need to demonstrate conclusively in what respect it disagrees with the amounts set out in K7.3 if it does not agree with that estimate.

The Parkway West Project

Union is proposing to spend about $224 million in the next three years (2012, 2013, and 2014) (V.9.2) on a new compressor, new pipeline headers and valves, and land and related common costs for a second Parkway station. From $80 million to $100 million will be spent in the test year, and the balance in 2014. At least $6 million will likely be spent in 2012 on compressor vendor engineering, planning and regulatory work, including a leave to construct application for the pipeline component of the work. An option has already been secured to purchase land for the project, valid until mid-2013. The project consists of two main parts, a third interconnection with Enbridge, separate from the existing connections at Parkway (Enbridge) and Lisgar, and a new 47,000 HP compressor.

$80 million is planned to be spent in the test year and is part of the test year capital budget.

Union states that the new compressor at Parkway West will enhance the current partial loss of critical unit ("LCU") protection for Parkway B, the larger of the two existing compressors at Parkway. The smaller of the two existing compressors at Parkway, Parkway A, currently provides 71% LCU protection for loss of Parkway B Parkway/TransCanada deliveries at Parkway (JB-1-7-5). The larger compressor provides 100% LCU protection for an outage of the smaller compressor. Union has two existing connections with Enbridge that do not require compression, one at Parkway on the suction side of the two Parkway compressors (in other words, the volumes that flow through the connection between Union at Parkway/Enbridge are not compressed), and one at Lisgar, a separate station two miles east of Parkway. These two connections which have capabilities of 1.2 bcf Parkway (suction) and 0.8 bcf (Lisgar), respectively. Compression at Union's Dawn, Bright and Lobo stations provide LCU protection for the volumes flowing through these connections. The third interconnection that Union proposes with Enbridge does not involve any additional Enbridge contractual volumes at Parkway at this time. Union plans to file for leave to construct the pipeline part of the Parkway West project this fall (JB-1-1-2). As the Board knows, leave to construct is not required for compressor additions.

Union has also recently concluded an open season for what it calls the Parkway Extension Project, seeking shipper commitments to contract with Union to underpin a proposed new pipeline from Parkway to Maple, to supplement the existing TransCanada capacity on its

Parkway to Maple pipeline, which Union says is insufficient and creates a bottleneck which prevents larger volumes of gas moving east and north from Parkway. Union estimates Parkway Extension will cost $360 million. Meanwhile, TransCanada recently received NEB approval to construct, and is now constructing a loop to the more westerly segment of its Parkway-Maple line, together with a shorter loop near Maple, and some enhancements to its Maple facilities, at a total estimated cost of $450 million.

As noted above, Enbridge has two existing connections with Union, one at the Enbridge (Parkway), on the suction side of the Parkway compressors, with a capacity of 1.6 PJs/day and another at Lisgar, two miles east of Parkway with a capacity of 0.8 PJs/day. Enbridge also takes approximately 250,000 GJs/day of gas compressed at Parkway. There is currently substantial excess capacity at each of these interconnections.

Finally, as part of its GTA reinforcement project, Enbridge is proposing to construct a 24 km long transmission pipeline from a new Albion city gate on its distribution system to Union Gas' proposed new Parkway West station, thus providing it with a third interconnection with Union, in addition to the connections it currently has at Parkway (Consumers) and Lisgar. Union and Enbridge had explored at some length through 2010 and 2011 and early 2012, joint ownership of the Parkway West to Albion pipeline, but Enbridge ultimately decided to build and own the line itself. Union and Enbridge had extensive discussions commencing in July 2010 and carrying on throughout 2011 and part of 2012 and developed a Memorandum of Understanding (MOU) to collaborate on a series of infrastructure initiatives emanating from Parkway (JB-1-7-8, Attachment 7, pp.2-3).

A Union proposal to its senior management to obtain design approval for the project stated, at p3, that:

> "In July of 2011, Union and Enbridge formed a study team to evaluate security of supply at Parkway and to look for synergistic solutions to re-enforce Parkway, create a new independent feed for Enbridge and to expand capacity on the constrained Parkway to Maple path
>
> Solution:
>
> - Union to build and own the Parkway West compressor station. Provides LCU protection for Parkway compressor volumes and provides bypass piping around existing station
> - With security of supply addressed, additional Parkway volumes could be considered
> - A new feed into the GTA from the Parkway West station to a new city gate for Enbridge at Albion is built. This section of pipe will be a Joint Venture between Union and Enbridge
> - Union builds and owns the remaining pipe from Albion to Maple. Union would then be able to provide seamless service between Dawn and Maple
> - Sum of all projects defined as "Parkway Projects" (JB-1-7-8, Attachment 7, p3)".

Mr. Reford testified that Union's proposed 50-50 joint ownership of the line, and their sole ownership of the line east of Albion, would have been the lowest cost solution to achieving both a third path to Enbridge and increasing the capacity of the Parkway to Maple corridor (V9, p37). Moreover, a recent Union open season RFP states that "joint ownership (with Enbridge) provides significant economics of sale, lower cost, environmental benefits, one pipeline through an urban environment reduces environmental footprint and impact on local residents" (JB.1-7-8, Attachment 13, p11). The alternative arrangements now being proposed, including a large feeder pipeline by Enbridge and a new compressor station and pipeline and other infrastructure at Parkway West will cost more. Both Union and Enbridge ratepayers will pay more as a result.

It is clear from the evidence that the Parkway West project and the Parkway Extension Project are closely linked in the minds of Union and probably Enbridge as well. The Parkway West Project is designed to underpin the increased volumes that Union expects would flow at Parkway in the next few years to relieve what Union considers to be a bottleneck because of the single 36" pipeline on part of the Parkway/Maple path, and to reassure Enbridge about the reliability of its supply in the event of a catastrophe at Parkway.

The projects are also linked together in the several presentations which Union managers made to senior Union and Spectra officers to obtain approval for funding for the projects and to third parties. For example, the Union presentation to its senior managers in April 2012 (JB-1-7-8, Attachment 7, p6), the projects are referred to as a "suite of projects" that will eliminate the bottleneck east of Parkway and provide Enbridge the third feed to the GTA (p7), and, at page 8 of the same document:

> "Parkway West facilities provide reliability and security of supply for customers east of Parkway and provide ability to reconstruct existing capacity and pursue expansion capacity".

Perhaps the clearest statement of the linkage is found at JB-1-7-8, Attachment 13, p3, in the presentation by Union to a Joint Enbridge and Union executive meeting on January 12, 2012, where Union states:

> "Parkway West Station constructed to provide (i) LCU coverage for Parkway compression, (ii) second (actually third), service feed at Parkway (in addition to Parkway Consumers and Lisgar); and (iii) feed and compression for Parkway to Maple Pipeline (Parkway D)".

Parkway West is characterized as a facility which would enable Union to tap new markets downstream of Parkway in Ontario, Quebec, and the northeastern United States, and as a part of a larger joint venture with Enbridge, in particular, a station to which Enbridge could connect its new transmission line, independent of those at Parkway station and Lisgar.

In BOMA's view, the evidence supports the view that, absent the Parkway Extension or an equivalent project by TransCanada, beyond the loop that TCPL is currently building, the new compression at Parkway West is unnecessary at this time. Union has not suggested that the new compressor is required to deliver gas to Enbridge Parkway West or any other proposed Parkway West connections. LCU for those connections is already provided on Union's system. The compressor is only necessary if and when Union achieves Board approval to construct the Parkway Extension because that would reflect the need for much greater volumes of gas moving through Parkway in the future.

Union states the LCU is necessary in the event of an outage of the Parkway B compressor. However, the likelihood of a serious compression failure at Parkway West is de minimus. Union's evidence is that the LCU protection which it wishes to provide by installing a compressor at Parkway West is the failure of the large compressor at Parkway. However, Union has stated that compressor reliability exceeds 99.9% over a ten year period (V8, pp. 95 and 96), and they agree that method of analysis that yielded the 99.9% reliability based on running time, when requested, is an appropriate measurement for compressor reliability (V8, 97). Current running times, however, do not seem that high (JB-1-7-5, pp 4-5). Furthermore, Union agreed that the addition of another compressor at Parkway West would not improve the reliability of the Dawn-Parkway system. Union also agreed that the pipeline failure of the Dawn-Parkway system (for example, the failure of valve system on the Dawn-Parkway) would be a 1 in 1,130 years event and a failure on a 35 degree day is a once in every 87,644 years event. As noted, Enbridge does not require compression at its existing Parkway (suction) and Lisgar interconnections with

Union, or at its planned new connection. Existing compressor capacity at the Dawn, Lobo and Bright station already have afforded LCU protection at those connections. Moreover, Enbridge currently takes a limited amount of gas after compression at Parkway, about 0.15 PJs on November 1, 2013 (J2.9) and BOMA's calculation.

Third, Union's projection that the "export" of gas through Parkway would increase to 3 PJ by 2015 or 2016 are just that, predictions. They have not yet been realized, and they seem at odds with Union's recent open season experience, in which it was unsuccessful in obtaining sufficient shipper interest to underpin a new pipeline from Parkway to Maple. The market was not there for such a service at this line. There would, therefore, appear to be little urgency for the Parkway extension at this time.

Given that the Parkway West compressor addition is not required for LCU at the present time, and it is more a platform for the Parkway expansion project, which is dependent on the expansion of markets, east of Parkway, including Enbridge, and given that Enbridge has proposed to build its own feeder line, which does not require compression by Union, the Board should not approve the Parkway West capital expenditures proposed on the test year (2013) capital budget.

While Union contends that it is not seeking any Board approvals in this case with respect to the Parkway West project, the Board has a practice of approving capital budget numbers when submitted as part of a rate case, and of raising with the applicant any concerns it may have as to desirability, and other potential project prudency risks associated with particular project expenditures, especially larger ones. The Board is right to do this, because the applicant should be forewarned prior to launching the large investments. Moreover, as a practical matter, it may not be possible to dismantle a huge project like a new pipeline/compressor station after it has been built. In this case, BOMA urges the Board to warn Union about the possible prudency risk of the expenditures in the proposed compressor station, given the apparent lack of need for it at this time. In the event the market ultimately develops, and comes to fruition, there will be time to construct Parkway West.

Nor will Union's upcoming leave to construct application for Parkway West be an opportunity to focus in detail on the <u>need</u> for the compressor as only the pipeline portion of Parkway West capital expenditures is, strictly speaking, subject to review. Union may very well argue at the leave to construct proceeding that the compressor expenditures are outside the scope of the case, notwithstanding their testimony in this case.

More generally, BOMA is of the view that the Parkway West project is the first of several dominoes, which, when all have fallen into place, will result in very large capital expenditure by Union, Enbridge, and TransCanada, which overlap, may very well not be the most cost effective way to proceed from a ratepayer's point of view, and will likely result in higher cost for ratepayers that would result from a more coordinated approach.

The Board should not wait for the Union and Enbridge Leave to Construct proceedings to encourage a prudent, least cost, solution for both Union and Enbridge ratepayers. It should act now to ensure that those proposed expenditures are considered in an Ontario wide context. Once the expenditures are underway, it would, as a practical matter, given their size and locations, be difficult for the Board to refuse to allow the facilities into rate base, or reject them in whole or in part on the grounds of prudency.

The magnitude of these proposals, and their strategic nature for all their utilities, require a more forward-looking approach.

<u>Conclusion</u>

The Board should not bless the Parkway West capital expenditures in the absence of further and better information on:

- need for the project in the absence of details on the Parkway Expansion proposed expenditures on new facilities by the three companies. These proposed facilities are large, and may easily cost in excess of $1 billion in the next three years. Ontario ratepayers will pay through rates for all the Union and Enbridge capital costs, and a portion of TransCanada's. These are not trivial sums.

- a thorough examination of Enbridge's Greater GTA project and will necessitate a connection with Union at Parkway West. It is not clear whether a new Union station needs to be constructed to support the Enbridge expansion. Could the Enbridge GTA line connect at or around Lisgar, for example?

- a clear understanding of the additional costs/ratepayers that Mr. Reford referred to that will result from both Union and Enbridge building transmission lines, rather than a joint line.

The Board should have both the Union and the Enbridge expansion plans in evidence before it makes a decision to approve either of the large capital projects in and around Parkway.

Moreover, the Board should not ignore TransCanada's offer to consult with Union and to devise a customized non-facilities or partial non-facilities solution to Parkway West LCU to the degree the Board thinks it is necessary, and to remove the constraint between Parkway and Maple. The Board should require TCPL, Union and Enbridge to discuss alternatives to Union and Enbridge facilities expenditures of well over $1 billion in the next few years. While TransCanada's initial suggestions were perhaps deficient in some respects, TCPL was acting in a relatively short period of time to what appeared to be an unexpected unilateral initiative by Union.

The parties should be asked to negotiate a solution that minimizes overall incremental capital costs while maintaining reliability and access to markets.

These discussions should take place before the Board accepts filings from either Union or Enbridge of their leave to construct applications for the respective projects.

If the parties are able to arrive at a solution, the Board must require TCPL to obtain NEB approval of any steps it must take as part of the Settlement, which requires its approval. Only then should it entertain leave to construct applications from Union and Enbridge.

If, after a decent interval, the parties cannot reach an agreement, then the Board should proceed to entertain the leave to construct applications. If Union and Enbridge can arrive at an agreement, but TCPL cannot agree with them, the Board should proceed with the Leaves to Construct application.

The Board should not accept at face value the proposition that Union, Enbridge and TCPL are competitors, and therefore, cannot be expected to negotiate a triparty solution. For the most part, Union and Enbridge are not competitors – they each have an exclusive franchise. Union and

TCPL have collaborated closely in this part so they obviously can work together if it is their common interest. They should not be permitted to insist on being able to have each their own projects for which ratepayers pay for, without the close scrutiny from the Board. For an Ontario ratepayer, it does not much matter how the Parkway corridor is expanded and who does it, as that the expansions are done in the most cost effective manner, and there are no artificial barriers placed on the movement of gas from Dawn through Parkway to Ontario, Quebec, and the US northeast markets. After all, Union and Enbridge are, or should be, first and foremost distribution businesses with adjacent storage facilities. While TransCanada cannot be given the opportunity to block access to markets, if that is what it is doing, collaboration should be possible.

In that connection, the Board should also initiate contracts with the National Energy Board, at the Board to Board level, to see if some procedural collaboration can be achieved, if only on the scheduling of any components of a just solution in the event one is reached. The contacts should not be left to the Ontario Ministry to initiate.

In-Franchise Revenue Forecast

For revenue forecasting purposes, Union divides its in-franchise customers into general service customers and contract customers. General service customers include a residential group (Rates M1 and 01), a commercial general services group (Rates M2, M4, 10 and 20), and a general service industrial group (Rates M2, M4, 10 and 20). The contract customers are also divided into three subgroups, an LCI group, which is a heterogeneous group of 430 mid-sized to larger commercial customers and mid-sized industrial customers (M2, M4, 10, 20), a greenhouse group, and a group of about 81 larger, mainly industrial, customers (mainly T1, 100). So Union, therefore, has 6 groups for revenue forecasting purposes. They prepare 6 different revenue forecasts. Five of these forecasts use a top down econometric forecast method but, importantly, each of the five forecasts is based on a unique structure or equation. Union uses a different forecasting methodology for the large industrial/commercial group, described as "bottoms-up" in the proceedings.

It is critical to understand that these five equations are different for each of the five groups that use the "top down" "economic" method to forecast 2013 volumes and revenues. While regression analysis techniques are used in validating each of the five forecasts, the underlying equations are different. The evidence and the discussion in the hearing has tended to conflate these two things. Each of the five equations contains different drivers (independent variables) reflecting the usage characteristics and economic profile of the group. For example, the greenhouse sector 2013 consumption and revenue is forecast using its own distinct equation, which alone among the five equations, contains as an independent variable, the price of #6 residual fuel oil. That driver reflects the fact that currently, virtually all Ontario greenhouses have dual fuel capability, a capability that is not present to the same extent in many of the other five groups, save for T1. Some T1 customers have dual fuel capability (with either oil or biomass) but their forecasts are prepared on a company by company basis, not using an equation.

Put another way, in order to critically assess the validity of the volume and revenue forecasts for all of its in-franchise rate classes, which are embraced by these six customer groups, one must, among other things, critically assess the validity of these equations and, in particular, the independent variables or drivers in the mathematical relationship which the equation expresses. Union has not provided information to the Board in a form which allows it to assess those equations.

For the sixth group, the largest industrial customers, Union conducts a company by company analysis and prepares an individual forecast for each of the 81 companies which ultimately reflects each company's own view of its likely consumption in the test year.

As noted above, within the general service group, Union proposes separate forecasts, for the residential, commercial and industrial users. BOMA believes that the forecasts for residential, commercial and industrial consumers all understate test year and volume revenues. The integrity of the general service customers [Rates M1, M2, 01 and 10] volume forecasts are critical to a fair estimate of Union's test year revenues because general service customers revenues constitute 86% of Union's in-franchise test year delivery revenues (C1, Summary Schedule 6; line 5 divided by line 24). The contract customers account for only 14% of total in-franchise revenues, notwithstanding the fact that they account for 64% of in-franchise throughput. (C1, Summary Schedule 1). By far, the larger part of in-franchise revenues are generated from residential, and small to mid-sized commercial customers, and within the general service group, the largest portion of that comes from the residential customers subgroup.

<u>Residential General Service Market</u>

When questioned about why it did not update its 2012 and 2013 (test year) forecasts at the time it updated its 2011 estimate to actuals, Mr. Gardiner said he did not do it because it was within his 2% "forecast error" (V2, p132). That is not a proper argument to avoid making a more current forecast which reflects the latest, best consumption information. Union made a similar point earlier (V2, p128), stating that a 1.7 variance in 2011 actuals over 2011 forecast, 2,264 m^3 vs. 2,227 m^3 for M1 (old M2) was not cause for concern because they were within the 2% "forecast error". But these small percentages reflect some fairly significant amounts of money when multiplied by general service residential volumes. For example, Union's evidence was that had they increased the NAC forecast for the test year for M1 (old M2) from 2,144 m^3 to 2,188 m^3, an increase of 1% in the incremental revenue would be about $3.5 million (V2, p137). Two percent equals $7 million. It does not seem reasonable to not update volume forecasts based on updated information solely because the difference in the total forecast revenue would be less than 2%, especially when the recent updates discussed in the evidence appear to be in the same direction – adjustments that increase volumes from forecasts to actuals.

Union declined to update the forecasts for 2012 and 2013 when it updated the 2011 actuals, notwithstanding the fact that there is a 5% decrease (116 m^3) between M1 2011 actuals to M1 2013 forecast. Union attributes part of the large percentage decrease in 2013 to replacement of 60,000 high efficiency furnaces in those years (V2, p134). But the 60,000 furnace replacements, with a commensurate effect on the EEI index has occurred each year in the last several years, when the average reduction year over year is more like 20 m^3, less than half of annual reduction what is projected for the period 2011 to 2013. Therefore, Union's statement that the increase furnace efficiency index accounted for 1/3 of the difference between 2011 M1 actuals (2,264 m^3) and forecast (2,227 m^3) seems unlikely. Why should the index increase when a forecast is translated into an actual? The number of furnaces actually replaced has not increased. It is a more or less constant number year over year. There is no evidence that the number of furnace replacements was higher in 2010 and 2011 in previous years. In general, BOMA agrees with the Board staff's analysis and recommendations for the residential customer revenue forecast.

Finally, BOMA does not see the rationale for Union's practice of "normalization" actual results as the basis of the 20 year declining trend, and then comparing those normalized NACs to the forecast, which is done using the same 20 year declining trend, to ascertain to what extent actuals are over or under the budget. Surely, a more powerful, cogent conclusion about the efficacy of the forecast comes from comparing the forecast volumes for the test year with the actual test year consumption. Making the comparison of normalized actual to normalized forecast results in a self-fulfilling prophecy; it does not assist one to select the best forecasting method. It is a mechanism that justifies the method already chosen.

The Commercial and Industrial General Service Groups

To reiterate, as noted above, BOMA is of the view that the residential, commercial and industrial general service groups test year forecasts are too low. Union has forecast an increase in total general service volumes from 2010 to 2013 of only 0.2% (C1, T1, p3, Table 1 REV), notwithstanding increases in the number of general service residential and commercial customers of 4.3% and 3.0% (Union South), respectively [C1, T1, p11].

Within the general service group, the residential volumes component is about 55%, the commercial about 35%, and the industrial 10% (V1, p119 and C1, T1, p3).

The equation which Union uses to forecast commercial normalized average use ("NAC") for the test year (2013) is a new equation first used in 2008 (C1, T1, p16), which is being examined in a hearing for the first time. The equation applies to general service commercial customers in Rates M1, M2, 01, and 10.

Union's evidence is that the general service commercial normalized average use is estimated using five drivers (independent variables) which are, in descending order of importance, weather, structural trend, "harvest season", structural base, and "binary dummy variables" (V1, p121).

I will address weather variable below, as part of a critique of Union's proposed change to its weather normalization policy.

The structural trend variable (C1, T1, p16) was introduced into the equation in 2008 to reflect the fact that the downward trend in the commercial NAC over the period 1991 to 2007 ceased in 2007 and began to track upwards (in Union's view, to flatline). The structural trend variable appeared necessary to reflect that shift. The evidence, in a chart entitled Commercial NAC Trend (C1, T1, p18), suggests that all the commercial rate classes start to trend upwards beginning around 2007, contrary to the view expressed by Mr. Gardiner (V1, pp121-122) who claimed that the curve simply flattened. That is not what the graph at p18 shows. The remaining three drivers of the equation "harvest seasonal weather conditions", a "structure base variable" and "binary dummy variables" were not explained in the evidence. Union stated that the harvest season variable, which is also new to the equation this year, accounts for weather conditions in the fall, and that "it is a proxy variable for temperature and cloud cover". But weather is already an independent variable; why does it need a second version for the fall? This discrepancy was not addressed in the evidence, nor does the evidence coherently explain the use of the structure base variable. Union agreed that "dummy variables" were used to eliminate a piece of data which <u>they</u> decided was "an outlier", in that it didn't fit their chosen trend line. The absence of clear and necessary explanations was endemic in the evidence on the volume/revenue forecasts. The evidence contained too much jargon, and in some instances was inconsistent.

Despite the upward bias in commercial NACs since 2006 for each commercial rate class (C1, T1, App A, p3), Union forecasts a decline in the commercial NAC from an actual amount of 17,006 in 2011 to 15,876 in 2013, a proposed reduction of over 6.5%. This is not a reasonable forecast, and has not been supported.

Even if the 2012 numbers turn out to be 16,500 m^3, which is what Mr. Gardiner says it is currently tracking, on a year to date basis (V1, p126), that is still 440 m^3 higher than what Union forecasts for 2012, 16,066 m^3 [C1, T1, p24], which is, in turn, 190 m^3 higher than the 15,876 m^3 forecast for 2013. The 2013 forecast should be increased to, at the very least, by 440 m^3, 16,316 m^3. That change would have a material impact on 2013 revenue for the general service group.

The same reversal of trend has occurred in the general service industrial sub-group forecast (Ex C, T1, p25); and Union has similarly ignored the inconvenient trend reversal in 2010-2011 by forecasting a lower number for 2013 than is currently forecast for 2012, albeit in this case by a much lower amount (2013, 493,389 m^3 vs. 2012, 495,412 m^3).

There is continuing confusion in the general service volumes in the evidence in the treatment of normalized average consumption and actual consumption.

The Contract Market

As noted above, the contract market consists of the LCI group, the greenhouse group, and the large volume user group. The LCI group (430 customers) accounts for 40% of contract group revenue. Union adopted an equation based "top down" method to forecast LCI group volumes again beginning in 2008. This hearing is the first time this equation has been examined. Union has forecast a decline. The LCI group contains industrial, commercial, and institutional customers.

Aside from the change in number of accounts upon which evidence has been tendered, which is not apparent in the evidence, the only significant driver of the LCI equation is the Can/US exchange rate. What has that to do with institutional or commercial load?

Union's evidence (see above) is that ratio of the Dawn natural gas price to the Fuel Oil #6 price ratio is a driver only in the greenhouse group equation.

Union has not provided evidence that the three main industrial sectors mentioned in the forecast (forestry, auto, and mining) and the commercial part of the group and has not addressed the commercial and institutional parts of the LCI subgroup. Anecdotal evidence suggests considerable growth in the mining sector in Ontario, not only in the northwest, where Union has recently constructed a pipeline to bring natural gas to the Red Lake mining camp (the largest gold mining complex in North America), but also in the northwestern and northeastern parts of the province, where gas service is already available. Moreover, the service sector has to have expanded in Ontario – new hospitals, colleges, universities, etc. While there have been closures in auto parts and forestry, most of these occurred some years ago. Some auto parts companies are clearly expanding. Nor have the commercial volumes/revenues in the LCI group been broken out which is odd given the different drivers for the growth of the sectors. Union has forecast number of $35.2 million, to $34.7 million for 2012 and 2013, after 2010 and 2011, actuals of $36.8 million and $36.4 million and 2007 actuals of $44.8 million, respectively. This forecast is unreasonable. Most economic evidence appears to be moving in the opposite direction, namely that Ontario and Canada are experiencing a slow but steady recovery from the financial crisis of 2008 to 2009. Union did not provide an actual recovery number for 2012 to date and by using Q1 2011 rates to calculate income, it has understated revenues. The Drummond Report submitted to the Ontario Government earlier this year forecast and growth of 2.2% in 2013 and 2014 and an average of 2% per year in 2015 through 2018.

Union has not provided sufficient evidence to support its 2013 contract customer revenue forecast, which show declines in revenue for 2012. Recent Stats Can announcements show

Ontario has added an average of 30,000 jobs per month so far in 2012. These numbers do not square with the LCI forecast. Manufacturing jobs, as a percentage of Ontario's total jobs, declined through 2010 but seem to have stabilized in 2011 at 11.8%, the same level as 2010 (Drummond Report, p84). Most private sector forecasters are forecasting 2.6 real GDP growth in 2013, and 2.7 real GDP growth in 2014 as the economy steadily returns to full potential (Drummond Report, p89) 2011 may well have been a low point in this cycle. The Ontario economy has grown steadily more recently.

Union has forecast actual reduction in demand in the LCI sector because of the high value of the Canadian dollar. BOMA does not believe Union's evidence demonstrates that the high value of the Canadian dollar, which has been at its current level for several years now, will materially affect demand in the commercial (including institutional) part of the LCI sector, in the manner suggested by Union. Union says that "Union projects demand destruction and further closure will continue in their commercial and industrial markets over the forecast periods". That is not a likely result, at least for the commercial sector of the market.

The Large Contract Customers Subgroup

The 81 larger customers account for 60% of in-franchise contract customer revenues. They are located in rate classes T1, M1 and 100. Union meets with each of these customers to present their forecast, based on that customer's last three years' actual volumes, and asks the customer to provide it with comments within a few weeks, and then finalizes its forecast. Union states that the customer makes the final decision on what volume Union includes in its forecast. If that is the case, that is wrong. Surely it is Union's responsibility to make and defend a forecast before the Board. Union should be required to endorse the forecast and its components.

Second, Union stated that the forecasts were made in mid-2011, about 18 months prior to the start of the test year, and sees no need to update them (V2, p141). Given the rapid change of events in the industrial trading sectors and the power sectors, these forecasts should be updated early in 2013 and then the revenue evidence adjusted accordingly. Union states that , there is no need to update the forecast for the Halton Hills power plant in light of the forecast, now that it has become clear that Lennox has greatly reduced its forecast (almost to zero), so that Halton Hills may have to pick up the slack in the gas-fired power market. It states that diversity effects will solve the problem, that is that some other power plants would likely be adjusted downwards. That view is almost certainly wrong (V2, p80). Most demand adjustments in the power sector at least, and probably other large volume sectors as well, eg. petrochemicals, steel, etc. are not unique, and idiosyncratic in nature. For example, a nuclear plant outage would require an increased contribution from several gas plants. Moreover, the large customer subgroups like power plants are not a large enough group to be able to assume a diversity effect. There are only a few of them. We are not talking here about several thousands of customers, only 81. It seems clear that along with the equation driver forecasting the residential forecasts should be updated to the next current date is practical.

Nor is it clear in Union's evidence why. Rates T1 and 100 volume, which appears to have bottomed in 2009, and increased each subsequent year, 2010, 2011 and 2012, are forecast to decline in 2013 (C1, T2, p11) and including and notwithstanding conversions from Rate M4 to T1 (C1, T2, p9, line 21).

Power Generation Sector Revenue Forecast

Most of the power generator sector is in T1 100 rate classes. Union has proposed a separate forecast for the gas-fired power generation sector based on conversations with its customers. The forecasts are made individually, like the other large volume customers. These customers include the gas-fired non-utility generators in northern and eastern Ontario, several more recently developed large gas-fired plants with output contracted to the OPA under so-called CES contracts and some "inside the fence" cogeneration facilities located at industrial facilities which operate in various modes. These large gas-fired power plants include Lennox (OPG), Lakehead (OPG), St. Clair Generating Station, East Windsor Cogeneration and Halton Hills. Union is forecasting test year revenues of 29.5 million for the power generation sector, compared to 2012 forecast of 29.7 million and to 2011 actuals of 32.7 million, 2010 actuals of 32.2 million and 2007 actuals of about 27 million (C1, T2, p13). Union's forecasts increases from 2007 approved revenue of $9.2 million for CES plants' revenue and the new Lakehead plant, offset by a reduction in $4.0 million from OPG's Lennox plant. The non-utility generator segment are forecast flat. (They are base load (self-dispatchable) facilities). The NUGs are the group of about 110 generators, varying in size from a few MWs to 200 MW. In total, they produce about 1,500 MW of power, of which 1,200 is gas-fired. These companies signed contracts with Ontario Hydro in the period 1987 to 1995 or so, and the revenue from which has been relatively stable over the period 2007-2013, Ontario Hydro having contracted to purchase all the plants could produce, for a period of anywhere from 20 to 50 years.

As noted above, BOMA is concerned that Union did not update its gas power plant volumes and revenue forecasts in the spring of 2013. This power sector is dynamic, a large consumer of gas, and changes can occur quickly.

Union forecast for the test year revenues of 29.5 million represent a reduction of 2.7 million from 2010 actuals, and a reduction in throughput from 2010 levels, from 2,349 10^6 m³ to 2,159 10^6 m³.

Union's gas-fired power forecast raises a number of questions. Given the growing role of gas-fired power in Ontario, that forecast is surprising. Gas is widely viewed as a back-up capability for intermittent renewable power supply, notably wind and solar, and wind power capacity has grown substantially in Ontario over the last three years. By November 2013, a total of 3,800 MW of wind and solar will be in operation (IESO 18 month report, June 18, 2012). During the next 18 months, an additional 500 MW of renewable will come into operation (IESO, June 2012 report).

Second, in contrast to the very modest forecast for 2013, Union's gas-fired plant will need to fill much of the ramping and swing producer role previously provided by coal. There is now 9,987 MW of installed gas-fired generation in Ontario, second in amount only to nuclear, with 11,406 MW.

Third, this modest forecast is at odds with various presentations Union has made to its own senior management and third parties highlighting the likely large increase in power demand for gas in the next few years. It is the largest single growth area for the company.

Fourth, Union forecasts no overrun revenue in 2013 for Halton Hills or any other power plant (J1.7) notwithstanding that actual overrun revenue were $300,000 in 2010, $600,000 in 2011, and $300,000 in 2012 to date (V1, p99). BOMA endorses Board staff's overrun revenue forecast.

Fifth, as in the case with large industrial customers, Union uses their initial mid-2011 forecast, as adjusted by the power producer, in this application. They do not feel updates are necessary. This approach is not right for either the power sector or the larger industrial sector of which power is a part, and will lead to anomalous results for several reasons. The practice, described in the previous section of allowing their customers to provide forecast, will raise conflicts of interest. In some cases, Union's shareholder and the customer may have coincident interests that support a "low ball" forecast – overrun revenue is a good example. No power producer wants to state "up front" that it will need overrun gas, as that could lead to a request that it increase its contract demand. It may also complicate its contractual relationship with the Ontario Power Authority. More important, Union should have a better overall view of the likely gas consumption of the gas-powered power plants in Ontario (and all of large industrial sectors generally, for that matter) than any one generator or one large industrial user as it is privy to much more confidential information. For example, Halton Hills has less information about the likelihood of Lennox operating in 2013 than Union does, yet Union accepted Halton Hills' estimate for 2013 without knowing whether Halton Hills was aware that OPG did not plan to run Lennox in 2013. In fact, the large gas plant owners, especially CES plants, view one another as competitors and would not share that information, except with a utility or government on a confidential basis (V1, p95).

Sixth, the larger power plants are unlike other large industrial customers, in that they are "dispatchable". They operate only when the IESO directs them to operate. The Union forecasts of throughput and revenues for CES plants are based on their operating as either intermediate level plants or peakers, i.e. plants that produce only at time of maximum demand, with a load factor of 5% or less. The load factors for the intermediate plants are higher. For example, the

Lakehead gas plant, now seeking a leave to construct before the Board, is thought to operate in 2013 as a peaker. However, that load factor may well increase later based on later years' developments in the power market. It is possible, for example, that the Northwest Ontario may experience a shortage of power given the forecast growth in demand and the extension of transmission to new mining development, in particular, if the East-West Tie Line is delayed. The IESO dispatch decisions are in part a function of the overall demand for power, and the performance of the current renewable power sources, nuclear plants, some non-peaking hydro, and the remaining coal plants. But the coal plants are on standby and will be shut by 2014 (by regulation). They produced no power in 2012. As the existing nuclear plants are taken out of service for overhaul, it is likely the running time of the gas plants will increase. An unplanned outage at a nuclear or major hydro plant would trigger a substantial increase in gas plant hours required and revenues to Union.

As an aside, whatever current forecast is for the test year 2013, it is clear that major new gas power plants will come into service in Ontario during the term of the next IRM program, beginning in 2014. While the ongoing conversion of coal fuel power plants, the greater use of existing gas plants, and the construction of new gas power plants and petrochemical plants in the United States will provide strong in-franchise and ex-franchise markets. If current test year volumes become the base for the next five years, Union will generate increased revenues which, absent a deferral account or Y-factor, will accrue to the shareholders. The Board should address this when reviewing Union's proposed IRM program next year.

Union's Proposed New Weather Normalization Methodology

Union proposes to change its weather normalization method from the current 55/45 blend of the 30 year average and the 20 year declining trend method to a 20 year declining trend. Union's witness described the 20 year declining trend as an "average with a slope" (V2, p43). But one could say a 30 year average has a slope as well, although less pronounced than the "20 year trend". The question is, what is the appropriate slope, which results in the most accurate forecasts of test year revenues?

It is generally accepted that weather forecasts of 18 months out are in the category of short term forecasts. Union is forecasting that only one number in this case, and that is what will actual number of degree days be in 2013. That forecast of degree days will then be used as a driver in several equations to help forecast general service residential and commercial customers normalized average use in 2013, and the overall general service consumption in 2013.

As the Board framed the question in RP-2003-0063, "the issue for the Board to consider is whether the 20 year trend methodology is a superior forecasting tool than the current 30 year moving average" (RP-2003-0063, p21).

The Board answered its question as follows:

"Union was unable to demonstrate that its proposal provided a clear and unambiguous improvement over the 30 year methodology". (Ibid, p22).

It is also generally accepted that while long term forecasts can be judged by a number of criteria, the critical determinant of whether a short term forecast is useful, is its accuracy. In other words, how close does the forecast come to the actual consumption in the year for which the forecast was made. As Rudder noted in its evidence (on behalf of Union) in EB-2005-0520 (in this case, JC-1-3-1, Attachment 1), "For models designed to forecast in the short term, the best indicator of forecasting success is the accuracy achieved by the forecasting process". He also noted that "short term models for electricity and gas utility forecasting are defined by Rudder as having a duration of one to two years (i.e. 12-24 months ahead)". Union's weather forecast for the test year qualifies as a short term forecast under this definition. The question for the short term forecast of degree days in 2013 should be judged the same way, based on its accuracy.

Given the context in which the forecast is made in a rates case, where overstated or understated forecasts have monetary consequences for the utility's shareholders and customers, BOMA agrees the element of symmetry needs to be considered; in other words, the forecast method should not produce degree day results that always fall short of, or exceed, the actual degree days. The degree day forecast is relevant to the heat sensitive load of the various customer groups; for example, for residential customers, Union's evidence (C1, T1, p18) suggests that approximately 60% of the total residential load is required for space heating purposes (30% is for water heating and 10% for various gas appliances).

Union's evidence suggested that accuracy and symmetry were the two most important criteria although Union appeared uncertain as to which came first. Three other criteria were mentioned as having less importance, stability, simplicity, and "sustainability", for which I think they mean credibility, which is a derivative of the other four criteria.

Union had proposed to move to a 20 year declining trend methodology in RP-2003-0063 (Union's 2004 rates case). At the time, Union was using the 30 year average method.

BOMA does not agree with Union's proposal to move to a 20 year declining trend weather normalization method at this time. BOMA proposes that, consistent with the Board's decision in RP-2003-0063 (paragraph 2.2) and section 2.2 of the Settlement Agreement in EB-2005-0520, the Board adopt a 50-50 blend of the 30 year average method and the 20 year declining trend method, for 2013 and the next IRM period. BOMA is of the view that leaping to a 20 year declining trend at this time would be inconsistent with the Board's earlier decision, and would not be justified by Union's evidence in this case.

Union's evidence is that moving to a 20 year declining trend would increase the 2013 revenue deficiency by $7 million. Moving to a 50-50 blend of the 30 year average and the 20 year declining trend would decrease the revenue deficiency by $6.323 million. In other words, the net increase from the current (2012) 55-45 blend would be approximately $677,000 (J2.2).

The Board decided to allow Union to introduce the 20 year declining trend into the forecast method on a gradual basis. In 2004, it set the ratio at 70% thirty year average and 30% declining trend, with the percentage of 20 year declining trend in the mix increasing each year over the next five years. The changes took place as directed 65-35 in 2005, 60-40 in 2006, 55-45 in 2007. In EB-2007-0606, Union again proposed that 20 year declining trend be used, but Union accepted that, as part of a Settlement Agreement in that case, that the 55-45 ratio be retained (V2, p 104). So Union has asked for the change repeatedly over the last several years, and each time it has been unsuccessful.

As noted above, BOMA is of the view that Union evidence has not justified its proposal. And, as noted above, the accuracy test should be a very simple one, which forecast method comes closest to the actual results (degree days) for the test year. A close examination of JC.2.2.1, p. 3 of 8 demonstrates that the 55-45 is more accurate than the 20 year trend. Table 2 on that page shows for each year from 1985 to 2011, inclusive, the Toronto Airport actual degree days, compared with the forecasts for those years using the 30 year average, the 20 year trend and the 55-45 blend methods, respectively.

BOMA has suggested, and Union has agreed, subject to check, that the forecast of degree days using the 55-45 blend method results in a number of degree days that is closer to the actual numbers than the forecast using the 20 year trend in 14 of the 26 years (V1, p109). Therefore, Union's statement in the second short paragraph on that page that "Please note that the 20 year declining trend produces weather normal estimate that is closest to the actual weather" is not correct. In BOMA's view, this fact, and Union's admission, is a very important point in that it answers the question, which method is more accurate. In the hearing, Union's witnesses, after agreeing with BOMA's observations, tried to move the discussion quickly to various statistical tests of accuracy, and claimed that they produced a more accurate result, but it was not able, or did not try, to explain away the results evident in the table. To repeat, the only result that should concern us here is which forecasting tool has yielded a number of degree days that is <u>closer to the actual degree days in more years</u> (our emphasis). Other more complicated abstract measures of accuracy over a multi-year period are of interest, but only secondary importance. Neither the pre-filed evidence, nor the witnesses, were able to demonstrate that their test for accuracy was superior to the simple test. If we track just the last 10 years, each method was closest in 5 of the

10 years. So the findings hold whether one looks at the full 26 year period, which Union has used to devise its 20 year trend, or just the last 10 years.

Looking at the symmetry of the two methods in the same table, the ratio of over-forecasts to under-forecasts of degree days was very close 16/10 for the 20 year trend and 17/9 for the 55-45. So from a fairness point of view, there is no substantial discrepancy.

The Union evidence shows that the 55-45 method is more stable and less volatile than the 20 year trend (V2, p115).

In our view, both methods are equally simple. Union agreed they were equally sustainable (V2, p115). Considering all the relevant factors, the blend of 30 year average and 20 year declining trend is superior.

While Union has attempted to refute this evidence by reference to "statistical accuracy" measures, that evidence is unclear. They have not clearly explained how the 20 year trend was determined to be more accurate, as defined above, by their statistical tests. They have done nothing to dispel BOMA's suspicion that they were trying to justify the results by creating statistical analysis that will do so. They have not explained clearly how the regression analyses works to produce the claimed result.

Their evidence is also inconsistent as to how much weight should be given to "statistical tests". For example (V2, p47), in answering Mr. Buonaguro, about why he did not do statistical tests, which would illustrate structural shifts affecting the time series he was using, in the face of large residuals, Mr. Gardiner stated, "so as we answered in the response to the IR, it is not about - it is not based on the merits of how strong the statistical results are, is it symmetrical, and relatively, is it more accurate" (V2, p47). BOMA has shown above that the 55-45 blend was a more accurate predictor of degree days in the "test year", in each historical case, the single year which was the subject of the forecast over the last 26 years. The cumulative absolute margins of the errors for the 25 year period, and other related matters, as determined by statistical tests, do not tell you which forecast method came closest most of the time. Table 2 does.

Third, in proposing the 20 year trend, as the exclusive test, Union appears to have much the same unwarranted conceptual leap and fell into the same non-sequitur that it did in 2004, namely, the world's climate is getting warmer, so we need a 20 year declining trend method. This step conflates climate change (small changes in degree days over long periods of time) and short term changes in weather.

The Board deemed Dr. Weaver's evidence to be of limited use in 2004 precisely because of that conflation. Dr. Weaver is an eminent climate scientist, but he addressed long term climatic trends over centuries. Union was attempting to use his science to predict weather 18 months in advance.

As for the origin of the proposal to make the 20 year trend the policy, Mr. Gardiner states "that it became evident in the 80's that the decline in degree days had become pronounced, and Mr. Root suggested we use a 20 year trend" (V2, p69). The problem with that point is that in many subsequent years since the "80's", the degree days increased on a year over year basis.

Moreover, Union states that the Board should accept the 20 year trend because it was already accepted as a component of the blend (V2, p70). That is not an argument to move to a 20 year declining trend as the sole forecast tool.

Finally, Union did not test the other methods that it tested in 2004 and that Enbridge tested.

Finally, surely, in creating (and assessing the reasonableness of) using a trend line to forecast degree days (weather) for a 12 month period commencing 18 months hence, and a trend make sense the <u>actual annual consumption numbers</u> as the starting point. After all, the only forecast that we are considering is a forecast of the actual consumption (and revenue derived therefrom) in the year 2013. The accuracy of that forecast for 2013 is simply how close the forecast number is to the actual for 2013. The only caveat to that is that the relationship of the forecasted number for the test year to actual number in the test year cannot always be in the same direction; in the interest of fairness, that is that there be a rough symmetry. Nor can the longer term fit of the trend line to normalized annual use numbers advance the analysis. Constructing the trend line from anything other than the actual annual consumption numbers is wrong.

<u>Cost Allocation and Rate Design Issue</u>

Of the phase II issues, BOMA has adopted the position put forward by Board staff with respect to several Cost Allocation and Rate Design issues, including:

- Cost Allocation – Parkway Station Costs and Related Rate Design
- Cost Allocation – utility vs. non-utility storage

General – Rate Design and Revenue Cost Ratios:

- Supplemental Service Charge
- Rate 01/10 and Rate M1/M2 Volume Breakpoint and Rate Block Harmonization Proposal for 2014

- Ratio mitigation

- Short-term Storage and other Delivery Services – Deferral Account (#179-70)

- Establishment of Storage and Transportation Margin Deferral Account

- Accounting Issues/Segmented Disclosure of Utility Business.