UNACCOUNTED FOR GAS STUDY

1. The purpose of this evidence is to present an unaccounted for gas ("UAF") study in accordance with the settlement agreement from the EB-2011-0008 proceeding (Exhibit N1, Tab 1, Schedule 1). The agreement states on page 14: *"Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study addressing what steps gas distribution utilities are taking in regard to measuring, forecasting, controlling the variability and managing the amount of unaccounted for gas volumes, and to compare what Enbridge is doing in respect of these issues relative to other gas distribution utilities."*

2. This UAF study is the first one conducted by Enbridge Gas Distribution Inc. ("Enbridge" or the "Company"). In preparing this study, discussion meetings with the Company's subject matter experts and benchmarking comparisons were conducted to address the requirements mentioned above. /u

3. The measurement and UAF management sections discuss the programs and processes that are are in place to enhance the measurement accuracy, to monitor the third party transmission pipelines' custody transfer metering accuracy, to strengthen the metering process and to manage the UAF by undertaking initiatives to reduce leaks in the pipe, third party damages to the pipe, release to the atmosphere during normal maintenance operations or theft. A comparison of these activities and UAF forecasting methodologies with other gas utilities concludes this study.

4. In summary, the Company either already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond the best practices and undertakes additional

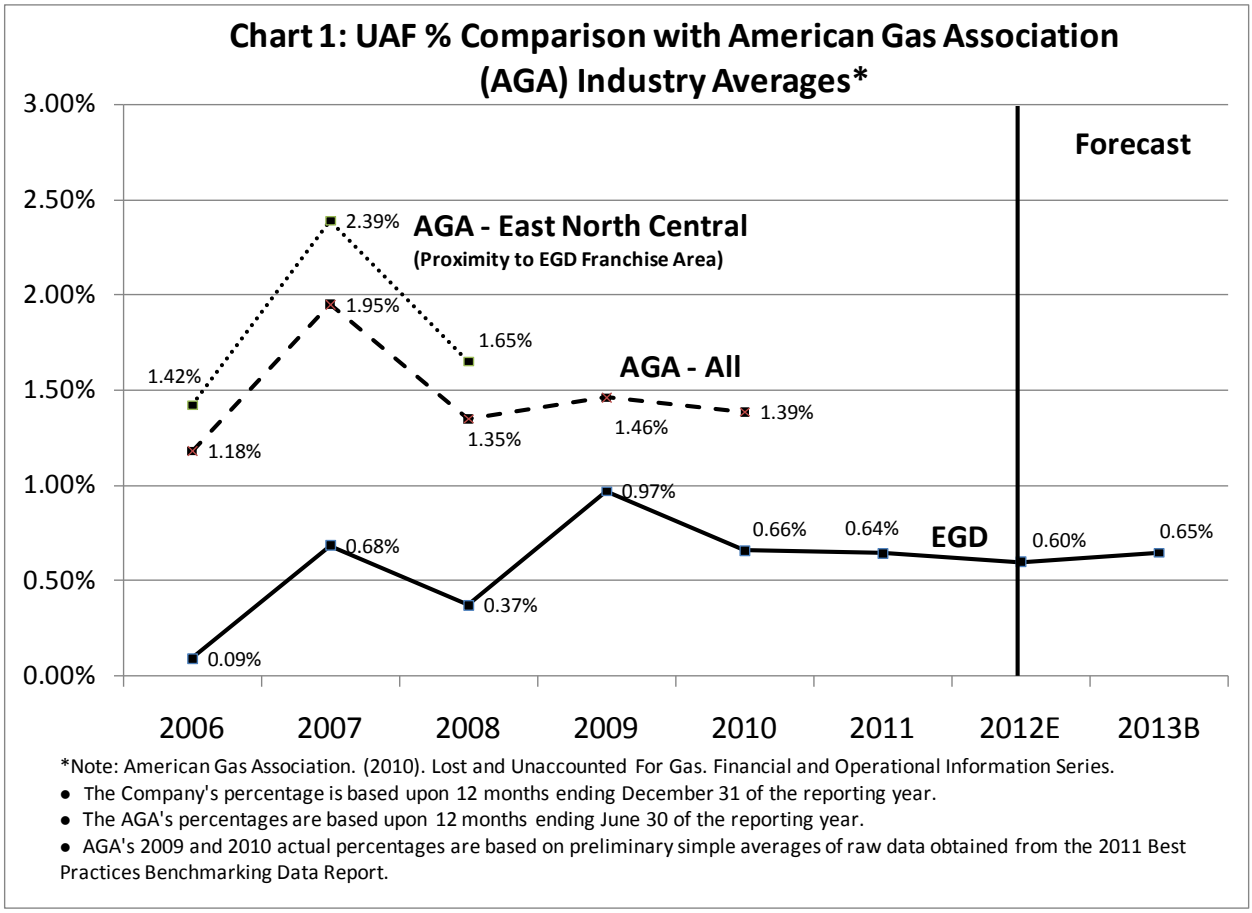
steps to minimize the measurement variations when possible. The remaining four practices that the Company has not implemented relate to using energy instead of volumetric units in billing end-use customers. The Company is currently not aware of other gas utilities within Ontario that have initiated this practice. As evidenced in Chart 1 on page 3, the Company's UAF percentage has been consistently lower than the industry averages of 172 utilities within North America. The Company's regression model performs better than the known objective forecasting methodologies in terms of forecast accuracy.

5. UAF is the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines (i.e. TransCanada Pipelines Limited ("TCPL"), and Union Gas Limited ("Union")) and the gas measured out of the utility system. In other words, UAF represents the difference between metered gas deliveries (or sendout) and metered consumption of the Company's 1.96 million customers.

6. For the purpose of comparing the Company's UAF with other gas distribution utilities, it is necessary to establish the UAF level expressed as percentage of total gas sendout. Chart 1 on the next page illustrates the Company's UAF percentage has been consistently lower than the American Gas Association ("AGA") industry averages of 172 utilities in North America.[1]

7. In recognition of the fact that UAF is volatile (Chart 1) and the fluctuating commodity costs associated with the UAF are beyond the control of utilities, currently there are 102 utilities in United States and Canada that have UAF true up mechanisms to enable them to recover the costs of unaccounted for gas that are not recovered from customers in the utilities' base cases.[2]

[1] American Gas Association. (2010). Lost and Unaccounted For Gas. Financial and Operational Information Series.
[2] American Gas Association. (2009). Lost and Unaccounted For Gas Cost Recovery Mechanisms. Natural Gas Rate Round-Up.



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8. UAF arises from meter differences, operational or external factors such as line leakage, unmetered uses and third party damage. It is known that gases are more difficult to measure than other concrete items, as measured volumes are highly affected by temperature and pressure. Measurement Canada also observes that gas meter measurement is "a pretty complicated mechanism".[3] An article from the AGA likewise stated that the primary cause of UAF is meter uncertainty.[4]

[3] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm03961.html
[4] American Gas Association. (2009). Lost and Unaccounted For Gas Cost Recovery Mechanisms. Natural Gas Rate Round-Up

Measurement and Variability Control

9. Accurate measurement of gas volume is a function of the meter and the factors used to adjust the meter read of compensating temperature, pressure, atmospheric pressure or elevation[5], and gas quality or heating value variations. These factors are applied to the meter read to compensate for the effect of the meter's operational environment on the volume of gas.

10. The Company's large volume customer meters are already adjusted for temperature and pressure variations. All mass market meters purchased after 1998 are already corrected for temperature as required by Measurement Canada. Meters that are not temperature corrected must be installed inside.

11. Prior to billing the metered consumption is adjusted for atmospheric pressure as prescribed by Measurement Canada. Enbridge began using the pressure factors (Rider F in the Rate Handbook) beginning in 2001 for meters that do not correct for atmospheric pressure in order to ensure appropriate billing regardless of elevation. Currently, the metered consumption is not adjusted for gas quality or heating value variation as the standard unit of natural gas volume measurement and consumer billing is cubic meters, a volumetric measure.

12. Billed volumes of 1.96 million customers are based upon the Company's metered volumes. All meters must be inspected and certified to Measurement Canada standards and comply with Canada's Electricity and Gas Inspection Act[6] and associated Regulations[7] before being installed in the field. The Company calibrates and maintains measurement equipment with the objective of keeping all

[5] Atmospheric pressure can affect meter reading. The higher the elevation is, the lower the atmospheric pressure. Natural gas expands at lower atmospheric pressures and contracts at higher. In other words, it expands on mountains and shrinks in valleys.
[6] http://laws-lois.justice.gc.ca/eng/acts/E-4/index.html
[7] http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131/index.html

metering variations within Measurement Canada's mandated tolerances. Accordingly, all new meters installed in the field must be within the tolerance level of +/- 1.0% and all in- service installed meters must be maintained within the tolerance level of +/- 3.0%. Measurement Canada audits the Company's metering performance annually. In addition, the Company has meter accuracy policy in place and examples are explained in the next section.

13. Additional steps are undertaken to strengthen the metering process and some examples are listed below.
    - All the large volume meter stations are inspected annually.
    - Mass market customer meters are inspected in accordance with the Measurement Canada sampling standard.[8]
    - All of the new or re-worked meters have to be calibrated within the tolerance level of +/-0.3% which is even lower than the tolerance level of +/-1% mentioned in the previous paragraph as prescribed by Measurement Canada.
    - Meter accuracy is monitored on a regular basis. If a meter's accuracy has deteriorated, the meter is replaced.
    - A doubtful meter process is conducted by the Company's Customer Care group. When the meter reader identifies that a meter is not registering, they send a code from their mobile device to the Work Management Centre to send a fitter out to validate and replace the meter if necessary.
    - There is software within the meter readers' mobile device which validates whether meter readings are within certain tolerance level or parameters.
    - Further validation of readings is performed by the billing system to verify the reasonableness of readings. If readings are outside the tolerance level, an incident is generated for the Company's back-office to confirm these readings manually.

[8] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04356.html

- Sampled billings are verified on a daily basis using test procedures to validate metered consumption against bill charges.

14. Billing estimation and variations between meter reading billing cycle and calendar month that are associated with operational uncertainties such as changes to number of people per household, number or type of gas furnace, changes to customer usage behavior, number of billing days per billing cycle and, move-in and move-out of customers, etc. were not included in the study because these kinds of variations typically cancel each other out over a twelve-month period. Accordingly, their impacts on the UAF are just temporary in nature.

15. Gas sendout volumes are defined as the total gas volumes determined from TCPL and Union Gas billed information based upon their respective measurement information at the various points of interconnection with the Company's distribution system. The measurement volume received from TCPL and Union is based upon their meter (custody transfer meter) information. Their meters are also inspected and certified to the Measurement Canada standard.

16. The Company has installed check meters that are operated in accordance with Canada's Electricity and Gas inspection Act and Regulations for each city gate station to monitor the accuracy of these custody transfer meters on a daily basis and whether they are within the +/- 2% tolerance permitted by applicable agreement. If the difference between custody transfer and check meter information falls outside this +/- 2% tolerance, the Company will investigate the variance and seek a resolution with TCPL and Union accordingly. The Company also reconciles, on a monthly basis, the custody transfer meter information against the many gas supply commodity, transportation and storage invoices.

17. TCPL and Union invoice quantities in in energy units (gigajoules (GJ)) in contrast to the volumetric units (cubic metres, (m^3)) used by the Company to bill its 1.96 million customers. Accordingly, invoiced amounts from TCPL and Union have to be converted to cubic meters based upon the corresponding quality or heating value of the gas. Depending upon the quality of gas acquired, the heating values can fluctuate on a daily basis and vary amongst different locations or sources.[9,10]

18. Chart 1 on page 3 illustrates that the Company's UAF% has ranged from 0.1 to 1%, on average, 0.6%, from 2006 to 2011. This percentage has been consistently lower than the AGA industry averages of 172 utilities in North America. The Company has always been complying with Measurement Canada meter verification tolerance limit of +/- 1.0 % and dispute tolerance of +/- 3.0% for 1.96 million gas meters . Given that the Company's own meter accuracy policy requires all of the new or re-worked meters have to be calibrated within the tolerance level of +/-0.3% which is even lower than the tolerance level of +/-1% as prescribed by Measurement Canada, any additional UAF% can be potentially attributed to the +/- 2% meter variations of the TCPL and Union and other system gas escape factors that are discussed in the UAF management section below. /u

19. The Company continues to control the measurement variability as described in detail above and to manage the amount of UAF as further discussed below in the management section. To the degree that the measurement variability is sourced from the third party transmission companies and is within the industry tolerance level of +/-2%, the year over year variability or fluctuation would be beyond the Company's control.

[9] www.transcanada.com/.../docs/.../Gas_Quality_Specifications_Fact_Sheet.pdf
[10] http://www.uniongas.com/aboutus/aboutng/composition.asp

20. All metered volumes are subject to the calibration and accuracy of the individual meters as well as environmental factors, such as heating value, which affect the gas volume measurement. In other words, the instruments cannot be calibrated to an absolute zero.[11] The nature of operations of the gas distribution business will always result in certain routine measurement variances due to metering differences, quality of the gas, and atmospheric pressure impacts.

21. To summarize measurement and variability considerations, the Company is in compliance with Measurement Canada requirements and benchmarks its metering process with respect to measurement variability with other gas utilities. The Company is one of the Measurement Canada accredited service providers. Accredited organizations are those organizations that have been delegated authority to inspect devices on behalf of Measurement Canada pursuant to the Electricity and Gas inspection Act. Enbridge is also one of the few organizations can provide more than two inspection type services.[12] Moreover, the Company set its meter accuracy policy to have lower tolerance level than the standard prescribed by Measurement Canada for new and re-worked meters. Finally, the Company uses its check meters to monitor the accuracy of custody transfer meters maintained by third party transmission pipelines to ensure metering variations are within the industry standard of +/-2% tolerance.

<u>UAF Management</u>

22. This section discusses the UAF that results from factors other than measurement variation. As gas flows through the pipe network, gas may be lost due to: leaks in the pipe; accidental damage to the pipe; release to the atmosphere during normal maintenance operations or; theft.

[11] http://www.feddevontario.gc.ca/eic/site/mc-mc.nsf/eng/lm00041.html.
[12] http://corporations.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00527.html#Enbridgee

23. First, leaks in the pipe are usually caused by factors such as corrosion, construction defects, material failure and third party excavators. The Company has multiple ongoing initiatives to address these issues. Initiatives include leak survey programs, leak detection and repair management system and, cast iron and bare steel mains replacement program. The program to replace cast iron and bare steel mains is scheduled to be completed by 2012 and is expected to reduce the leak or break failure rate of the Company's gas mains.

24. Second, the greatest risk facing the Company's pipelines is damage caused by third party excavators. Over the last 10 years, the number of recorded damages per 1,000 locates has decreased by 70%. Total damages have decreased by 36% during this same timeframe, and locate error rates have decreased by 15%. Over this same period, locate requests have increased 112%. Even though the activity level has increased significantly as reflected by the increase in locate requests damages and locator errors have dropped sharply due to an increased focus on education and training for both excavators and locators.

25. The Company continuously seeks new ways to protect pipeline assets through innovative strategies and incorporating industry best practices. Initiatives include: completing a marketing research study on effectiveness of consumer communications programs; training presentations for locators and excavators; efforts to move forward on a single national phone number (811); legislation to establish a mandatory One Call system in Ontario, and improved tracer wire technology in order to provide additional protection to assets.

26. Third, during normal maintenance procedures or emergency shutdowns, gas is released to the atmosphere inevitably. Referred to as "blowdown", this venting of natural gas from a pressurized system occurs due to maintenance or emergency procedures such as taking a system offline for repair or emergency pressure

release. The Company has undertaken various steps to prevent, recapture, reduce, or redirect vented emissions from a pressurized system containing gas. Examples of these steps are: flaring; compression; pressure reduction; volume reduction and; blowdown avoidance. For other safety and integrity projects, please refer to Exhibit B1, Tab 3, Schedules 1 and 2. /u

27. Lastly, with respect to the theft or unmetered use, the Company has a number of initiatives already in place. For instance, a report is run on a monthly basis to monitor large volume customer meters that are installed but not turned on; and meter readers are trained to identify signs of gas bypass or potential theft. In addition, a new program was implemented in October 2011 to provide meter readers with a financial reward every time they identify gas bypass or potential theft.

28. As a further comment on the Company's commitment to managing UAF Enbridge has been participating in the CSA Canadian GHG Challenge Registry and voluntarily reporting its fugitive emissions since the mid-1990s.[13] While broader in scope than simply managing fugitive emissions the submitted action plans has been evaluated to either gold or silver status since 2002.[14] The Company's 2011 plan is currently in development. These action plans and recommendations will be integrated with the Company's operations to minimize the system gas escape and green house gas emissions from a system-wide perspective.

29. Overall, as these factors impact the distribution system's safety and reliability which is the Company's top priority, the Company has been, on an ongoing basis, undertaking multiple initiatives and steps to manage these factors. While it is difficult to quantify the impact of these factors on UAF, the Company does not believe the impact is material.

[13] Fugitive emissions are emissions, other than venting and flaring from above and below-ground pipeline networks and facilities that are unintentional and include third party system damages.
[14] http://www.ghgregistries.ca/challenge/cha_entity_e.cfm?No=52

Comparison with Other Gas Distribution Utilities – Measurement and Management

30. Table 2 below compares the best practices benchmarking results from other gas distribution utilities with respect to steps taken to measure, control the variability and manage UAF.

Table 2: Comparison with Other Gas Distribution Utilities: Measurement and Management

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
1. Incentive to accurately account for UAF ▪ Report UAF in dollars on the annual report.	✓ The volumetric variations were reported on the annual information form. Readers can calculate the dollars from the pricing information within the MD&A report. ✓✓ The Company has been voluntarily reporting and managing fugitive emissions since the mid-1990s. The submitted action plan has been evaluated to either gold or silver status since 2002. ✓✓ A customer meter field measurement program has been undertaken to obtain better emission factors from fugitive equipment leaks on natural gas metering systems.
Billed volume accuracy ▪ Utilize SOx guidelines. ▪ Establish practices that meet Sarbanes-Oxley requirements.	✓ The Company has utilized SOx guidelines and has established multiple SOx controls. These controls are tested and validated by external auditors annually as part of the SOx certification process to ensure the volumes billed to customers are based upon the metered numbers input to the billing application. ✓ Sampled billings are verified on a daily basis using test procedures to validate metered consumption against bill charges.

[15] American Gas Association. (2004). Lost and Unaccounted for Gas Roundtable Results. *Best Practices Benchmarking.* This benchmarking study is the latest and the most comprehensive study of North American available from either internet sites or large Gas Association membership directories or paper records.

[16] ✓✓ denotes the Company goes beyond the best practice
✓ denotes the Company adopts the same practice
× represents the Company currently has not endorsed the same practice
○ corresponds to the Company is either currently in progress in embracing the same practices or partially accepting the practices

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
	✓ There is another validation level within the billing system to validate if the readings are reasonable. If the readings are outside the tolerance level, an incident is generated for the back-office to work on these readings manually.
2. Accuracy of Suppliers' custody meter reads. ▪ Install a check meter at city gate stations. ▪ Develop a real time handoff to Storage Operational Data Acquisition (SCADA) of Meter Data. ▪ Perform a weekly review of the daily data.	✓ The Company has installed check meters that are operated in accordance with Canada's Electricity and Gas Inspection Act and Regulations for each city gate station. ✓ The check meter data is obtained from the SCADA data system automatically at a 24/7 monitoring centre based in Edmonton. ✓✓ The data is monitored on a daily basis.
3. Establish a Meter Test program by meter class. ▪ Ongoing verification that pressure factors and meter accuracy meet standards.	✓ All meters must be inspected and certified to the Measurement Canada standards before being installed in the field. ✓✓ Each year, the Company also conducts sample testing on accuracy of measuring devices. Based on a sample of 424 meters, the average accuracy for the period 2007-2010 is about 0.44% which is lower than the Measurement Canada prescribed standard for meter accuracy of +/-3%. ✓✓ All of the large volume meter stations are inspected annually. ✓✓ Meter accuracy is monitored on a regular basis. If meters have deteriorated, they are replaced. ✓✓ A doubtful meter process is conducted by Customer Care group. When the meter reader identifies that a meter is not registering, a code is sent from the handheld to Work Management Centre to send a fitter out to validate and replace the meter if necessary. ✓✓ There is software within the meter readers' handhelds to validate whether the readings are within certain tolerance level or parameters. ✓✓The Company's meter accuracy policy has lower tolerance levels than the standard prescribed by Measurement Canada for new and re-worked meters.

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
▪ Monitor new elevated pressure meter installations on a monthly basis.	× New elevated pressure meter installations are not monitored on a monthly basis as processes are already in place to ensure the Company's meter performance is in accordance with Measurement Canada standards. Atmospheric pressure factors from Rider F of the rate handbook are then applied to the metered volumes automatically based upon the geographic region of the meter.
4. Accuracy of large volume meters at low flow periods. ▪ Install dual meter runs – one low volume and one high volume.	○ Dual-run meters are only used for emergencies. For customers that have unique load, dual meter runs are installed, one large meter for high volume and one small meter for seasonal or low measurement.
5. Divide the system into energy (e.g. BTU, GJ, etc) zones for more accurate volume (DTH, m^3) calculations. ▪ Separate the system into energy zones. ▪ Determine the energy value for each zone. ▪ Automate the energy to volume relationship by customer for billing.	 × Not warranted at this time. × Same comment as above. × Same comment as above.
6. Automatic calculation of the UAF. ▪ Develop appropriate programs to encompass or analyze all data including deliveries, inputs, receipts, billing, etc.	○The Company has already initiated multiple IT projects to automate the calculation of the UAF by storing gas deliveries, purchases, and receipts into a data warehouse application.
7. Proper measurement equipments are selected and installed for each meter or regulator application. ▪ Establish a measurement training program ▪ Establish measurement policies and procedures ▪ Create a standard table of compatible meter and regulator combinations	 ✓ Yes. ✓ Yes. ✓ Yes.
8. Establish a cross functional team to monitor and discuss the UAF on a monthly basis.	○There is a cross functional team to monitor and discuss the UAF on a quarterly basis. The monthly practice will be considered after the data warehouse application of automating UAF calculation is implemented.

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
9. Reduce theft of service. ▪ Provide incentives for field staff to identify theft of gas.	✓ A report is run on a monthly basis to monitor large volume meters that are installed but not turned on. ✓ Meter readers are trained to identify signs of gas bypass or potential theft.
▪ Provide monetary reward to customers who report theft or unauthorized use.	○ Not warranted at this time but will be monitored.
▪ Develop a training program for field employees on identifying theft or unauthorized use.	✓ A new program was already implemented in October 2011 to provide meter readers with a financial reward every time they have identified gas bypass or potential theft.

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31. In summary, the Company either already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond the best practices and undertakes additional steps to minimize the measurement variations when possible. The remaining four practices that the Company has not implemented relate to using energy instead of volumetric units in billing end-use customers. The Company is currently not aware of other gas utilities within Ontario that have initiated this practice.

Comparison with Other Gas Distribution Utilities – Forecast

32. Please refer to Exhibit D3, Tab 4, Schedule 1, for a detailed discussion of the steps undertaken by the Company in forecasting the amount of UAF. The UAF forecast is calculated using a regression model. The major driver variables in the model are active meter customers, and other qualitative variables of reflecting the size of the distribution system and structural changes. Table 1 of Exhibit D3, Tab 4, Schedule 1, illustrates that the Company's regression model continues to outperform other alternative regression model specifications by producing lower in-sample and out-of-sample forecast variations than the alternative ones.

Witness: I. Chan

33. Given that the best practices benchmarking forecast performance of the UAF forecasting methodologies are not publicly available, the Company has compiled its own summary of UAF forecasting practices in North America by posting questions to the Gas Forecasters Forum[17], contacting utilities directly and researching regulatory evidence filed by utilities.

34. Table 3 on the next page demonstrates that there are four utilities currently adopting five-year average forecasting methodology, one utility embracing the three-year weighted average forecasting methodology, and the balance use subjective judgment forecasting methodology. Therefore, the five-year average forecast methodology appears to be the predominant approach amongst these eight utilities. Excluding the subjective judgement UAF forecasting methodologies, five-year average and three-year weighted average, are examined by comparing their mean square errors with the Company's regression model approach over the historical period 2006-2011, and the results are set out in Table 4 on page 17.[18] /u

[17] http://www.southerngas.org/index.php/gas-supply-marketing/201.
[18] 2006 is the first year that the Company prepares the budget numbers on a calendar year basis.

Table 3: UAF Forecasting Methodologies and Performance Comparison of North American Gas Utilities

Gas Utilities	Number of Customers	UAF Forecasting Methodologies	UAF Forecasting Performance
American	4.3 millions	Subjective judgement: 3-year average or a 1-year average depending on which average is judged to be the best predictor of the future.	Do not formally track the accuracy of the forecasts
American	2.3 millions	5-year simple average	Do not formally track the accuracy of the forecasts
American	3.3 millions	Subjective judgement: 4-year average or other recent actual depending on which average is judged to be the best predictor of the future.	Do not formally track the accuracy of the forecasts
American	0.7 millions	5-year simple average	Negotiated Amount
American	2.1 millions	5-year simple average	Do not formally track the accuracy of the forecasts
Canadian	1.3 millions	3-year weighted average	Present both forecast and actual within regulatory filing. 2006-2011 MAE* = 53 $10^6 m^3$.
Canadian	0.2 millions	Subjective judgement: 8-year average	Do not formally track the accuracy of the forecasts
Canadian	0.9 millions	5-year simple average	Do not formally track the accuracy of the forecasts

35. Mean absolute error ("MAE")[19] is used to evaluate the forecast accuracy of various methodologies because the Company's unaccounted for gas variance account ("UAFVA") is measured as the variance between actual and forecast levels. According to this criterion, the best forecasting methodology provides the smallest deviation between actual and forecast and the direction of the deviation is neutral to all stakeholders. In Table 4 provided on the following page, the Company's regression model performs better than the other forecasting methodologies adopted in North American utilities according to the MAE criterion.

[19] The formula used to calculate the mean absolute error is: $MAE = \frac{1}{n}\sum_{t=1}^{n}|(a_t - f_t)$ where n = the number of time periods, a= actual, f= forecast, t= time reference.

Table 4: Comparison of Forecast Performance - UAF Forecasting Methodologies

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
					Forecast vs Actual Variance		
Year	Actual	The Company's Regression Model - In-Sample Forecast	3-Year Weighted Average	5-Year Average	The Company's Model vs Actual	3-Year Weighted Average vs Actual	5-Year Average vs Actual
2006	10,274	46,636	12,728	19,742	36,362	2,454	9,468
2007	83,823	51,311	(65,967)	6,676	(32,512)	(149,790)	(77,147)
2008	44,424	55,691	67,498	21,584	11,267	23,074	(22,840)
2009	110,917	58,108	65,733	26,186	(52,809)	(45,185)	(84,731)
2010	72,104	62,183	89,070	52,851	(9,920)	16,967	(19,253)
2011	73,355	66,870	85,625	64,308	(6,485)	12,270	(9,047)
2012*	68,134		89,254	76,925			
2013*	73,092		71,267	73,787			
				Mean Absolute Error:	24,893	41,623	37,081

*denotes forecast numbers

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36. In summary, the Company's regression model approach is the best performing methodology among other known forecasting methodologies used in North American utilities in terms of forecast accuracy. It provides the smallest deviation between actual and forecast volumes over the historical period. Developing a forecasting model is an on-going process. This model passes a battery of statistical tests and is valid given the current and historical information as described in Exhibit D3, Tab 4, Schedule 1. Consistent with the past practise, the model will be continuously evaluated, tested, and refined as new information becomes available.

Conclusion

37. As evidenced in Chart 1 on page 3 of this exhibit, the Company's UAF percentage has been consistently lower than the industry averages of 172 utilities within North America. The Company's regression model performs better than the known forecasting methodologies in terms of forecast accuracy. The Company either

already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond best practices and undertakes additional steps to minimize measurement variations when possible.

38. There are some factors beyond the Company's control, such as metering variations from third party transmission pipelines and metering technology. As measurement is a sophisticated but imperfect estimation process, the accuracy of all of the meter information can only be evaluated within the required percentage of tolerance instead of an absolute value. Therefore, some uncertainty always exists. Best practices can reduce but not eliminate uncertainty.

39. As always, the Company will continue to evaluate and invest in cost effective new technologies and processes to control variability and manage the amount of UAF for the factors that the Company can control or influence.